B.C. Hydro

Twenty-Year Resource Plan

For the period
1988 to 2007

Resource Planning
Corporate Affairs

March 1988

B.C. HYDRO

TWENTY-YEAR RESOURCE PLAN

FOR THE PERIOD
1988 - 2007

RESOURCE PLANNING
CORPORATE AFFAIRS

MARCH 1988

20/5/824

Canadian Cataloguing in Publication Data

B.C. Hydro. Resource Planning.
Twenty-year resource plan for the period, 1988-2007

ISBN 0-7726-0811-3

1. B.C. Hydro. 2. Electric power - British Columbia - Planning. I. Title. II. Title: 20-year resource plan for the Period, 1988-2007.

HD9685.C33B32 1988 333.79'32'09711 C88-092098-X

20/5/895

TABLE OF CONTENTS

EXECUTIVE SUMMARY

1. INTRODUCTION

2. ANALYTICAL FRAMEWORK

   2.1 Existing Resources
   2.2 Technical Planning Criteria
   2.3 Economic Criteria

3. DEMAND FORECAST

   3.1 General Approach
   3.2 Assumptions
   3.3 Probable Requirements
   3.4 Uncertainty

4. MARKETING AND DEMAND-SIDE MANAGEMENT

   4.1 Industrial Marketing Programs
   4.2 Interruptible Marketing Programs
   4.3 Demand-Side Management Programs
   4.4 Export Market Outlook

5. POTENTIAL RESOURCES

   5.1 Coordination and Purchases
   5.2 Efficiency Improvements
   5.3 Downstream Benefits Arising from Columbia River Treaty
   5.4 New Generation Projects

6. TWENTY-YEAR RESOURCE PLAN

   6.1 Recommended Plan
   6.2 Sensitivity Analysis
   6.3 Contingency Options
   6.4 Implications of Possible Export Sales

7. ACTION PLAN

Appendix I
Existing System Technical Characteristics

Appendix II
System Technical Planning Criteria

Appendix III
Potential Projects

EXECUTIVE SUMMARY

This report describes B.C. Hydro's selected strategy and related actions to meet future customer requirements for electricity within prescribed standards of reliability and cost, and also in accordance with the objectives of Hydro as an agency of the Provincial Government.

As a public utility, B.C. Hydro has a mandate to provide for the most efficient use of provincial electrical energy resources while contributing to the economic development of British Columbia. In the face of an uncertain future, Hydro's plans must attempt to balance quality of service and rate levels; address environmental and regulatory concerns; and consistently optimize the supply, marketing and management of existing and planned resources.

The most recent electricity demand projections (September 1987) are approximately 1400 GW.h higher for the mid-1990's than forecast the year before, due to higher residential and commercial sales, and also higher sales in the paper and allied products sector, but somewhat moderated by lower sales in the metal mining sector. However, uncertainty in the long-term provincial economic outlook is reflected in a fairly wide range of possible forecast outcomes.

Given current demand projections, the firm hydro surplus situation experienced by B.C. Hydro since the early 1980's is expected to last until 1989. Combined existing hydro and thermal resources plus limited off-peak purchases using the existing interconnection with Alberta are sufficient to satisfy demands until about 1995. Beyond that time, rapidly increasing supply costs and unacceptable service risks require the addition of new resources.

B.C. Hydro's response to this outlook in the short term is to utilize all possible opportunities to ensure the efficient management of existing resources. Thus, active marketing efforts are being made in the domestic and export markets, while a much expanded emphasis has been placed on demand-side management programs and the promotion of other energy saving measures in the generation, transmission and distribution of electricity.

In the longer term, this year's Resource Plan continues to move in the direction of increased reliance on purchases and coordination agreements with other energy producers, thereby postponing the need for new generation projects until after the turn of the century. Negotiations are currently underway with Alcan and the Bonneville Power Administration and contacts have also been made with TransAlta and domestic private power producers for the possible purchase of energy, and potential added benefits from coordinated planning and operation of resources. In addition, the downstream benefits arising from the Columbia River Treaty will begin reverting to British Columbia in 1998. The Plan assumes that these energy benefits will be available to meet domestic demands, although resolution of this issue is still pending.

The selection of the next generation addition to the system around the year 2000 focused on three projects (Peace Site C, Keenleyside and Murphy Creek), since they offer the lowest costs among all the potential projects, sizes compatible with forecast demand growth, shortest lead times to bring them to operation, and comparatively small environmental impacts. Beyond these developments, the Hat Creek thermal project appears to offer advantages in scheduling flexibility and marginally better economics than the alternative hydroelectric projects, although further studies are still required.

Recommended Twenty-Year Resource Plan

Year	Resource	Annual Energy Contribution
1988	Demand-Side Management Programs	Increasing to about 3000 GW.h by 2003.
1989	Coordination of Columbia River projects with BPA	1300 GW.h
1995	Coordination/purchase agreement with Alcan	3000 GW.h
1998	Return of Columbia River Downstream Benefits	Increasing to about 4800 GW.h by 2003.
2001	Peace Site C	4700 GW.h
2004	Keenleyside	1160 GW.h
2004	Murphy Creek	1450 GW.h
2006	Hat Creek	11800 GW.h

The recommended plan represents the optimum scheduling of new resources and most efficient use of existing and future resources so that the expected cost of meeting a potential range of forecast demands is minimized while required quality of service standards are also satisfied.

The Plan was analyzed to determine how it could be modified to respond to higher or lower demand growth scenarios, and also to potential unavailability of currently scheduled resources. Only extreme outcomes (ie. clearly outside the energy planning range) would produce temporary significant energy surpluses or sharply higher production costs. The unavailability of the Columbia River downstream benefits (worth about $1 billion) would have a more severe financial impact on B.C. Hydro than failing to secure a purchase/coordination agreement with Alcan, or from DSM

programs that perform below expectations. However, the timing of the next generation addition would be more critically affected by the lack of the Alcan purchase: Site C would then be required four years earlier, in 1997. Rates could be impacted over ten to fifteen years by anywhere from 2% to as much as 10% as a result of these contingencies.

This Resource Plan requires a number of actions to be undertaken during fiscal year 1988/89:

i) Completion of negotiations with Alcan for a purchase/coordination agreement.

ii) Reaching of agreement with BPA on coordinated operation of Columbia River projects.

iii) Sufficient progress on DSM program evaluation, design and implementation to ensure satisfactory levels of customer response and program performance.

iv) Establishment of a policy for energy purchases from cogenerators and other private power producers.

v) Firming up of preliminary studies on benefits from coordinated planning and operation with TransAlta.

vi) Rehabilitation work at a number of generating stations to ensure future performance/safety standards. Review of small project efficiency improvements.

vii) Work on a new Kelly Lake - Cheekeye 500 kV transmission line to provide security of service to the Lower Mainland, and also on new 287 kV Skeena-Kitimat and Williston-Kelly Lake 500 kV lines, if agreement is reached with Alcan.

viii) Development of a provincial export policy, and a decision on the future use of the Columbia River downstream benefits.

1. INTRODUCTION

This report describes the strategies and related actions required for B.C. Hydro to develop its generation and associated transmission system to meet future customer requirements reliably and economically.

As a public utility, B.C. Hydro has a mandate to provide for the most efficient use of provincial electrical energy resources while contributing to the economic development of British Columbia. In the face of an uncertain future, B.C. Hydro's plans must attempt to balance quality of service and rate levels; address environmental and regulatory concerns; and consistently optimize the supply, marketing and management of existing and planned resources.

The planning process is dynamic by nature, as conditions are constantly evolving. Uncertainty in the long-term provincial economic outlook gives rise to a wide range of possible demand forecast outcomes. The firm hydro surplus situation experienced by B.C. Hydro since the early 1980's is expected to last until 1989, thus increased emphasis continues to be placed on domestic and export marketing. At the same time, overall efficiency considerations have promoted an expanded scope for demand-side management activities. This year's Resource Plan also continues to move in the direction of increased reliance on purchases and coordination agreements with other energy producers, while new projects do not appear to be required before the turn of the century. Negotiations are ongoing with interested parties in the U.S. for possible sales of firm power. In the meantime, because B.C. Hydro's generating system consists primarily of hydroelectric plants, surplus secondary energy which will be available under all but low water conditions continues to be sold in the spot export market and to domestic interruptible customers.

This document attempts to outline B.C. Hydro's selected development strategy in response to an uncertain future. Its purpose is threefold: to highlight the direction recommended and the actions accordingly required; to record the underlying philosophy, assumptions and temporary results to provide a focus for ongoing discussion; and to supply the necessary information for budgetary and financial purposes. The Plan is updated annually as new information becomes available.

The report is organized as follows. Section 2 outlines the main assumptions and planning criteria guiding the subsequent evaluation of alternative plans and options. Section 3 introduces the electric demand forecast that will be used in the preparation of the Resource Plan, including a brief methodological overview. Section 4 discusses the various marketing activities currently underway in Hydro which impact upon planned balances between demands and resources, for example interruptible and conservation programs, and

potential export market sales. Section 5 reviews the potential resources available to meet future load growth in the B.C. Hydro system (new projects, purchases, coordination agreements, etc.). Section 6 presents the recommended Twenty-Year Resource Plan and discusses how it could be modified to respond to a variety of possible alternative outcomes. Finally, Section 7 lists the actions required during fiscal year 1988/89 to ensure that the Plan can be implemented. Appendices I, II and III expand on the system technical characteristics and planning criteria used to develop the Plan. Information on additions to transmission, stations, and control and communications equipment can be found in the report "Electric System Development Plan", issued annually by the System Planning Division.

2. ANALYTICAL FRAMEWORK

B.C. Hydro's objectives are to achieve a most efficient use of resources, to maximize the contribution to provincial economic development and to provide superior customer service. The Resource Plan is a key element towards meeting those objectives and its formulation has to reflect a careful balancing of potentially conflicting criteria. Building expensive generating facilities to foster economic develoment may, for example, be incompatible with attaining most efficient status. Numerous alternatives are evaluated to ensure that future requirements for high quality service are met in the most economic way possible. Economic development objectives are served by providing relatively low cost power throughout the Province, including planning for service to economic development zones not currently served by the integrated system, and also through pursuing export market opportunities.

A variety of assumptions, procedures, economic and technical criteria are required in the formulation of the Resource Plan. Technical criteria are required to ensure that adequate quality of service is provided to customers, while economic criteria ensures consistency with overall economic and financial goals for the utility. The planning criteria are reviewed and modified from time to time to reflect changing conditions. This section outlines briefly the major assumptions used in the preparation of this twenty-year Plan.

2.1 EXISTING RESOURCES

The annual output of B.C. Hydro's existing hydroelectric system can vary between about 42500 GWh and 52000 GW.h depending on streamflow conditions. In addition, some 3700 GW.h can be provided by thermal plants (Burrard and gas turbines), as required to meet demands.

The cost of operating the hydroelectric plants, which make up 90% of existing resources is essentially fixed, with most of it going to cover depreciation and interest charges. Their variable cost is about 0.4¢/kW.h. to pay for water rental fees.

Burrard Thermal's operation (900 MW, 3170 GW.h/a capability) relies on the use of off-peak "valley" natural gas fuel available in all but the coldest months, at a cost of 1.6¢/kW.h currently, estimated to escalate to about 2.1¢/kW.h by the mid-1990's (1987 dollars). A further 2000 GW.h/a could be generated by Burrard if required in the 1990's, by arranging a firm gas contract, at an incremental cost estimated to be about 2.8¢/kW.h (1987). Future natural gas prices are significantly uncertain, however.

Additional energy would be available from two standby gas turbines (146 MW, 550 GW.h/a), although at a high incremental cost (approximately 6¢ kW.h). Interconnections with other energy producers would allow purchases from Alcan, Transalta and the U.S. if required.

The total average cost of operating the system (including distribution, taxes and finance charges) is about 4.0¢/kW.h.

Further details on the technical characteristics of the B.C. Hydro existing system can be found in Appendix I.

2.2 TECHNICAL PLANNING CRITERIA

Resource Scheduling

Plant additions and energy purchases are scheduled so that the expected cost of meeting energy demands over the long-term is minimized. A probabilistic approach is used which considers essentially all possible combinations of demand forecasts, hydroelectric system water conditions, energy purchases, demand-side management programs and other resources. Alternative plans selected must provide sufficient flexibility to meet a range of demand forecasts, with higher cost resources being required to serve high growth outcomes. It is possible that for some adverse combinations of loads, water conditions and non-firm resource availabilities, not all demands could be served. The probability and size of such deficits is a measure of the risk inherent in each alternative plan. Project advancements or deferrals may be required to meet higher or lower load growth beyond ten years. Temporary surpluses of hydro energy (arising from a slow domestic growth scenario) may be marketed in the U.S.

Reliability

In addition to the traditional "loss of load" reliability criteria of "one day in ten years" to ensure an adequate capacity margin to meet peak loads, B.C. Hydro requires that the maximum energy shortfall in any future year be less than 0.8% of total annual energy demand. This criterion assumes the full range of probabilistic combinations of load uncertainty and resource availability, although beyond ten years load uncertainty can be attenuated by some resource rescheduling flexibility.

Transmission

Much of the transmission system has been built to integrate the generating plants. System strengthening through station and circuit additions will be necessary as domestic requirements

increase. In general, the transmission system is designed to be capable of withstanding a single contingency outage during peak load periods or other high-stress conditions. In addition, other performance standards relating to maximum circuit loads and security of service are to be met.

Appendix II discusses in some detail the technical criteria currently used to plan resource additions to the existing electric system.

2.3 ECONOMIC CRITERIA

Feasible alternative resource plans (ie. those that meet the technical criteria) are made up of a combination of potential purchases, demand-side management programs and new projects. Capital, operating, energy purchase and other costs associated with each plan are evaluated using the discounted cash flow method. The following economic and financial parameters have been used:

- Net discount rate: 5% per annum (resulting from assuming long-term inflation and interest rates of 5% and 10% per annum respectively).
- Corporate overhead rate: estimated to be about 5% for large projects, increasing gradually for smaller projects (eg. 10% for a project worth $20 million).
- Water Rental Fees: 0.4¢/kW.h (energy) plus $2.85/kW (capacity), constant until 1989; assumed to increase tied to Hydro rates thereafter.
- Natural Gas Prices: About $1.5/GJ (1987); assumed to escalate to approximately $2.8/GJ by the mid 1990's (constant 1987 dollars).
- Operating costs: Approximately 0.5% per annum of total capital costs for hydroelectric plants (excluding water rentals and taxes); 1.0%, 3.3% and 1.6% per annum for coal-fired, gas/oil-fired thermal plants, and gas turbines, respectively.
- Taxes: Annual grants and school taxes paid are approximately equivalent to 1.3% of plant capital costs.

3. DEMAND FORECAST

3.1 GENERAL APPROACH

B.C. Hydro's electric load forecast includes projections for short and long-term sales, gross energy and peak demands in B.C. The forecast is developed by residential, commercial and industrial components, and is usually updated on an annual basis. The major economic drivers for the forecast are obtained from provincial government agencies with specific inputs on key industrial areas and energy prices from consultants.

The population, economic, sectoral and energy price forecasts are translated into electricity requirements by projecting household formation, commercial activity and industrial production. Changes anticipated in customers' consumption patterns are also introduced in arriving at the electricity forecast.

The impacts of relative energy price changes are also examined by establishing the scope customers have for installation of more efficient equipment, higher levels of insulation, fuel substitution, modification of existing processes, and self-generation of electricity.

Demand projections are prepared for up to 20 years for use in long range planning.

3.2 ASSUMPTIONS

The B.C. economy is forecast to average 2.9 percent real annual growth over the period to 1997 and 2.8 percent in the following 10-year period to 2007. The main growth areas through 1997 are projected to be paper and allied products manufacturing, non-resource based manufacturing, construction, and community, business and personal services.

Population growth in the 1.3 percent to 1.4 percent range on an average annual basis is expected through the 20-year period.

Electricity prices are assumed to increase at less than the rate of inflation (in particular through the early 1990's) and maintain their competitive position vis a vis oil and natural gas.

3.3 PROBABLE REQUIREMENTS

For the probable forecast, electric energy requirements are projected to increase from about 40200 GW.h in 1987/88 to 51510 GW.h by 1997/98, and to 68260 GW.h by 2007/08 for an

annual average growth rate of 2.8 percent. This is 1400 GW.h higher for 1997/98 than was forecast in 1986, due to higher residential and commercial sales, higher sales in the paper and allied products sector, but somewhat moderated by lower sales in the metal mining sector.

Marketing and Demand-Side Management Programs will have increasing effect on actual load growth and load shape in the B.C. Hydro system. The impact of the Electric Plus and DSM programs is not factored directly into this forecast, but is later dealt with in the preparation of the Resource Plan (see Sections 4 and 6).

3.4 UNCERTAINTY

It is necessary in planning to pay at least as much attention to the uncertainty in the forecast as it is to the probable outcome itself. Thus, a range of forecasts, reflecting the possible variance around the expected, or probable forecast, is also prepared.

- The band between the Probable High and Probable Low forecasts is assumed to include 80% of the possible forecast outcomes. This band reflects the uncertainty inherent in the forecast even if the economic projections (GDP and population) materialize.

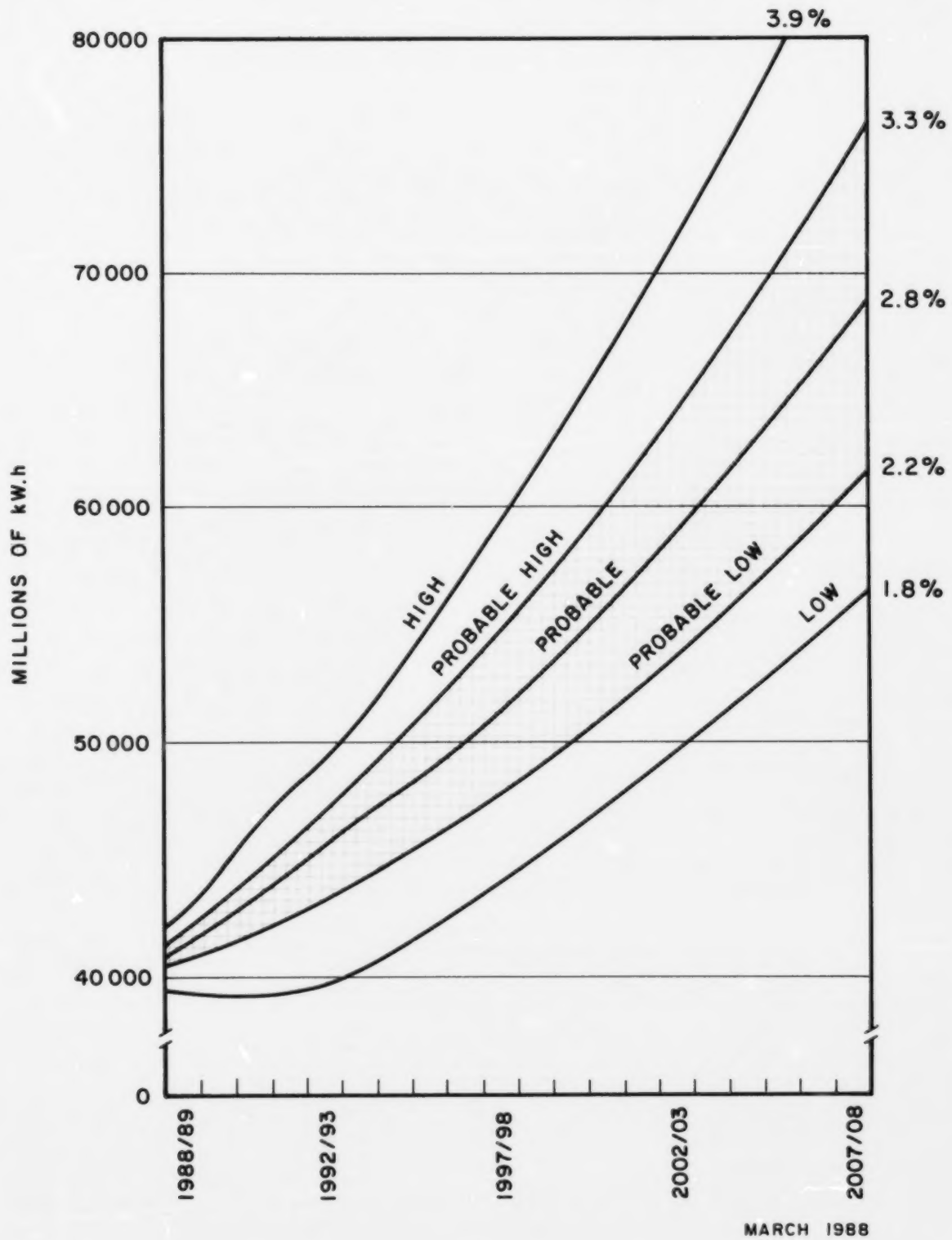
- Two different economic scenarios reflecting markedly different development paths for B.C. have also been developed, resulting in the Low and High energy forecasts.

Gross requirements for the various forecasts for the integrated system are shown graphically in Exhibit 3-1 and also summarized in Exhibit II-1 (Appendix II).

Further details on the demand forecast are provided in B.C. Hydro's document "Electric Load Forecast 1987/88 - 2007/08", prepared by the Load Forecast Department.

EXHIBIT 3-1

RANGE OF FORECAST DEMANDS



MARCH 1988

4. MARKETING AND DEMAND SIDE MANAGEMENT

Four major areas where B.C. Hydro is currently active are included here. Their focus is on optimizing the utilization of existing and planned facilities and on supporting economic activity in the province.

The Firm Industrial Marketing Programs were initiated to market surplus electricity at reduced rates to help domestic industry to be more competitive, or in some cases to remain operational. The Interruptible Electric Marketing Programs (called Electric Plus) were recently introduced to provide reduced rates to domestic customers by marketing a portion of the secondary energy that is generally available with a hydro system. The Demand-Side Management (DSM) Programs are intended to reduce load through enhanced conservation thus allowing deferrals of future generation projects. Export market activities have attempted to market both firm and secondary energy surplus to domestic needs, in addition to exploring the possibility of building for export.

4.1 INDUSTRIAL MARKETING PROGRAMS

These programs will be winding down over the next three to four years. Estimated demands have become part of the industrial sector load forecast and can be found in the Load Forecast document.

The Turbine Turndown program has allowed purchased electricity to replace the pulp and paper mills' own generation from heavy fuel oil or wood waste. Sales under the Industrial Electricity Rate Discount Act (Bill 28) have been mainly intended to promote increased production, expansion and new industry (primarily in the mining and chemical sectors). The Critical Industries Act (Bill 31) was a vehicle for reopening or keeping open industries in B.C. through electricity rate discounts which were part of a package of taxation, labour cost and other concessions.

4.2 INTERRUPTIBLE MARKETING PROGRAMS (ELECTRIC PLUS)

The intent of the programs, launched in the summer of 1987, is to market interruptible surplus electricity at reduced rates to customers currently using another fuel. The programs were intended to utilize approximately 2000 GW.h/annum, about half the secondary energy normally available in the B.C. Hydro system.

The Residential Program involves the addition of electric space or water heating, with the present heating equipment now becoming backup. (existing electric heating systems may also qualify by adding an appropriate alternate fuel backup system.)

The General Program is intended for commercial and industrial customers and is similar to the Residential Program, but it is also available for industrial process heating. The Electric Steam Boilers Program is intended to promote the use of interruptible electricity to produce steam, as a replacement for fuel oil.

The programs are still in their infancy and no clear indication exists yet as to their actual rate of penetration and total incremental load. Their impact could be significant, particularly on regional peak demands. New sales of 450 GW.h have been assumed by 1990/91.

4.3 DEMAND-SIDE MANAGEMENT PROGRAMS

Demand-Side Management (DSM) refers to all deliberate utility activities designed to influence customer use of energy in a way that will produce desired changes in the utility's load. This may involve load building or load reduction. The Electric Plus Program can be classified as a strategic load building initiative.

The bulk of B.C. Hydro's current efforts on DSM are directed towards future load reduction, to be achieved through energy conservation initiatives. For B.C. Hydro, the benefit of load reduction programs results primarily from their impact on the timing of new generation projects and reduction of energy purchases. Provided DSM measures are timed properly and cost less than new generation resources, deferral of new capacity reduces total costs and revenue requirements.

This Resource Plan reflects a substantial increase in emphasis on DSM programs, which have been expanded from five in last year's Plan to approximately twenty this year, with associated energy savings double those estimated earlier. These programs cover all three market segments - residential, commercial and industrial.

The Residential Programs fall into three broad categories, encouraging fuel substitution, improving the energy efficiency of the building envelope, and encouraging the use of more efficient lighting and appliances. These programs will use promotion and incentives to influence energy use. The Commercial Program will address both the building envelope and major energy uses such as lighting and air conditioning, and will rely on audits for existing buildings and design assistance for new structures. The Industrial Programs will initially promote energy efficient motors, variable speed drives, plus higher efficiency industrial and street lighting.

As these programs are developed beyond the concept phase, some may be terminated. However, additional programs may also be identified as new, more energy-efficient technologies emerge. Current estimates suggest unit costs for the majority of these programs in the range of 0.3 to 2.1¢/kW.h and total energy savings increasing from approximately 1000 GW.h in the early 1990's to over 3000 GW.h twenty years into the future.

In addition, peak control programs are being investigated, which are intended to defer substation or distribution reinforcement costs by reducing or shifting a part of the peak load in areas where existing facilities are nearing their load limits.

Exhibit II-2 (in Appendix II) shows currently projected equivalent generation that would be saved by the introduction of DSM programs. Expected values shown include transmission and distribution losses that would be incurred if the energy was purchased or generated.

4.4 EXPORT MARKET OUTLOOK

Potential long term markets for power exports from B.C., for both energy and capacity, are emerging in both the U.S. Pacific Northwest and Pacific Southwest. Competition comes from hydroelectric and coal-fired generation in the Northwest, and coal, oil and gas-fired generation in the Southwest. In addition, BPA's current surplus position has resulted in a restrictive policy which denies B.C. Hydro firm wheeling through the BPA system while also limiting firm access to California markets (BPA intertie access policy).

Short term sales are difficult to forecast with any certainty because they depend on rainfall in the Northwest and oil and gas prices. Prior to the early 1990's the outlook is for non-firm energy sales to displace thermal generation in the U.S. and to support reservoir refill. Prices are likely to be low, probably below 2¢/kW.h, although they should improve rapidly in the early 1990's, to possibly 3-4¢/kW.h for combined sales of firm energy and capacity (border price, in Canadian dollars).

There is also a substantial degree of uncertainty for long-term sales. By the late 1990's California and the Northwest will likely need new generation, but load forecasts, oil and gas prices, completion of nuclear stations in Washington State and availability of non-utility generation make future market volumes and prices quite uncertain at this time. B.C. Hydro access to these markets in the mid and late 1990's will require negotiated arrangements with BPA.

B.C. Hydro has received expressions of interest from several U.S. companies, and is currently involved in discussions with Washington Water Power and Puget Sound Power & Light for possible sales of firm, secondary energy and capacity. Commercial arrangements may be finalized in 1988-89, and long-term sales contracts could commence in the early and mid 1990's, depending on completion of the required transmission interconnections. The various contracts could add up to over 1000 MW of capacity and 4000-5000 GW.h of energy. Prices in the mid to late 1990's are expected to be higher, i.e. in the range of 4.5 to 5.0¢/kW.h. (Border price for combined energy and capacity, Canadian dollars.)

B.C. Hydro may improve its access to the U.S. markets by agreeing to some form of coordinated operation with BPA. Also, a market will likely exist for resale of the Canadian share of the Columbia River Treaty downstream benefits, which belong to B.C., beginning in 1998/99.

The provincial government and B.C. Hydro have promoted the development of the Site C Project on the Peace River, in advance of domestic need, to export a block of firm energy for a fixed term, eg. 20-25 years. Expressions of interest have also been made by private developers on both Site C and a thermal plant in the East Kootenays. However, given the nature of the market requirements and the question of deliverability (wheeling), B.C. Hydro will have to play a major role in such sales. In addition, any long-term export contract would be expected to pay all financial charges and return a profit, thus not increasing rates to B.C. Hydro's domestic customers. The advancement of project construction work would provide jobs to the provincial economy.

Development of a provincial export policy is expected in 1988. B.C. Hydro will work with the Provincial government towards the concept of a "single window" Export Agency which is necessary to coordinate the interests of potential private suppliers, the government and Hydro's customers.

5. POTENTIAL RESOURCES

As the period of firm energy surplus ends in the early 1990's, B.C. Hydro will require additional energy to meet projected load growth. The following resources appear to be the most economic available to serve the incremental demands.

5.1 COORDINATION AND PURCHASES

A number of possible coordination and purchase agreements with neighbouring utilities and private power producers offer a potentially attractive combination of flexibility and fairly priced energy to B.C. Hydro.

(a) TransAlta

Significant benefits can be achieved from coordinating the planning and operation of Alberta's utilities with B.C. Hydro. TransAlta, primarily a thermal-plant utility, can offer off-peak coal-fired energy which B.C. Hydro can utilize to increase its system firm energy capability and thus defer construction of new plant. (Conversely, B.C. Hydro can sell economic secondary energy and peaking capability to Alberta). B.C. Hydro currently accounts for some of this coordination potential by assuming that up to 2000 GW.h could be available annually from TransAlta's coal-fired thermal plants. An additional 1000 to 2000 GW.h could be provided at higher cost by TransAlta's gas-fired plants.

(b) Bonneville Power Administration

Coordination with BPA would make it possible to make more effective use of B.C. Hydro's reservoir storage at Mica and Williston. It is estimated that coordinated operation of Hydro's Columbia River projects with BPA could firm 1300 GW.h/a of secondary hydro energy for B.C. Hydro. Full coordination of all B.C. Hydro and BPA reservoir storage could provide a total annual increase of 2800 GW.h to B.C. Hydro, although it may unduly restrict the operation of the Hydro system.

Current negotiations with BPA are focused on reaching a limited coordination agreement by 1989, with full coordination as a somewhat distant possibility.

(c) Alcan

Alcan has announced plans to expand their installed capacity at Kemano in the mid-1990's to increase aluminum production. Initially, Alcan may proceed with the Kemano

Completion project without expanding smelting capacity. Discussions between B.C. Hydro and Alcan are ongoing for the purchase of Alcan's excess hydroelectric energy for a period of perhaps 20 to 25 years. Up to about 2800 GW.h per year of firm energy could be available in the mid 1990's. Coordination of the operation of Hydro and Alcan reservoirs is estimated to yield an additional net energy gain of 260 GW.h (firm) to B.C. Hydro. Prices are under negotiation.

(d) Other

B.C. Hydro will purchase energy from private power producers, including cogenerators, provided such purchases can be shown not to have a negative impact on Hydro's rates. To this end, a policy is being developed by B.C. Hydro that will establish terms for energy purchases.

The amount and cost of cogenerated electricity which could be surplus to the needs of local industry is under study. (The B.C. pulp and paper industry has developed approximately 470 MW of wood waste-fired cogeneration capacity to date). Current B.C. Hydro planning studies assume a potential of up to 2500 GW.h/annum of energy from these sources. This estimate is currently under review.

Purchases from other sources appear to be less likely. Since both BPA and B.C. Hydro are predominantly hydro utilities and adverse water conditions would probably affect them simultaneously, it is not likely that surpluses would be available for purchase from BPA. However, utilities further down the Pacific Coast operate oil, gas and coal-fired generation. In a serious emergency, it is possible that up to 4000 GW.h per year of expensive electric energy could be purchased from U.S. utilities.

Alternative energy sources such as small hydro, biomass (wood waste) and wind resources offer potential for remote communities currently being served by diesel generation. Negotiations are under way for supply from a small hydro project on Moresby Island, Queen Charlotte Islands.

5.2 EFFICIENCY IMPROVEMENTS

Improving the efficiency of the existing system by reducing electrical and hydraulic losses may provide an additional cost-effective source of energy. It is estimated that up to 1400 GW.h per year of energy could be either added or saved by adopting measures such as substituting more efficient turbine runners and rewinding generators in older plants; lining

diversion tunnels with concrete to reduce friction losses; raising the top elevation of some existing reservoirs; and increasing plant output by diverting nearby watersheds into existing reservoirs.

In addition, efficiency improvements in the area of distribution can be achieved by voltage upgrades of heavily-loaded distribution circuits, and by replacing distribution feeders with larger conductors.

The economic attractiveness of these energy-saving measures is currently being investigated. No allowance has been made in this Plan for potential gains/savings, pending completion of these studies.

5.3 DOWNSTREAM BENEFITS ARISING FROM COLUMBIA RIVER TREATY

The Canadian entitlement to downstream power and energy benefits resulting from the operation of storage at the Duncan, Keenleyside and Mica Projects under the Columbia River Treaty was sold to the United States for a period of 30 years from the commencement of operation of each project. Thus, these power benefits will revert to British Columbia gradually, beginning in 1998/99.

The magnitude of the annual downstream benefits (DSBs) after 1998/99 depends upon several factors. It is most sensitive to the rate of electric load growth in the Northwestern United States and to the amount of thermal and hydroelectric resources used to serve this load growth. A high electric load growth in the United States served by thermal additions has the effect of reducing the Canadian entitlement at a faster rate than either low growth rates or use of other resources to serve new growth. The latest available BPA load forecast was used to develop the DSB estimates shown in Exhibit II-3 (Appendix II).

In addition to energy, the DSBs have a substantial peak component. Both the capacity and energy benefits are expected to decline with time as the U.S. system grows. The downstream benefits belong to B.C. according to the Canada - B.C. agreement dated 8 July 1963, and could provide a very valuable resource to the province in the early 2000's.

5.4 NEW GENERATION PROJECTS

As indicated in Section 3, the annual demand for electricity in the B.C. Hydro Integrated System is expected to grow from approximately 40200 GW.h in 1987 to 68000 GW.h twenty years later, in 2007, according to the probable forecast. While coordination agreements, purchases, efficiency improvements and the return of the Columbia River Treaty downstream benefits are

expected to make a significant contribution to meeting the new demands, construction of some new generation projects will likely be required, for service probably beginning by the turn of the century.

The following projects appear to be the most economic available to meet the additional domestic demands.

	Average Energy Capability (GW.h)	Earliest Feasible In-Service Date
Hydroelectric		
Peace Site C	4700	1996
Keenleyside	1160	1997
Murphy Creek	1450	1998
Seven Mile Unit 4	280	1993
Stikine - Iskut	15600	2003
Liard	18400	2008
Thermal		
Hat Creek	12000	1998

The energy costs of Site C and the combined Keenleyside/Murphy development are nearly equal and appear to be the lowest cost energy projects that B.C. Hydro could construct within existing developed river basins. Other hydroelectric and thermal projects have also been studied by B.C. Hydro. However, the degree of engineering and environmental information available for these projects differs considerably. Further studies would be required before any could be considered for licensing.

The relative energy costs and expected annual energy contribution of demand-side management, cogeneration, several future hydroelectric projects and the Hat Creek Thermal Project are shown in Exhibit 5-1, compared to the Revelstoke hydroelectric project, if built today. Preliminary estimates of the capacity, energy capability, earliest in-service dates and approximate cost of the projects can be found in Appendix III.

COMPARISON OF ENERGY COSTS AT 5% NET DISCOUNT RATE OVER PROJECT LIFE

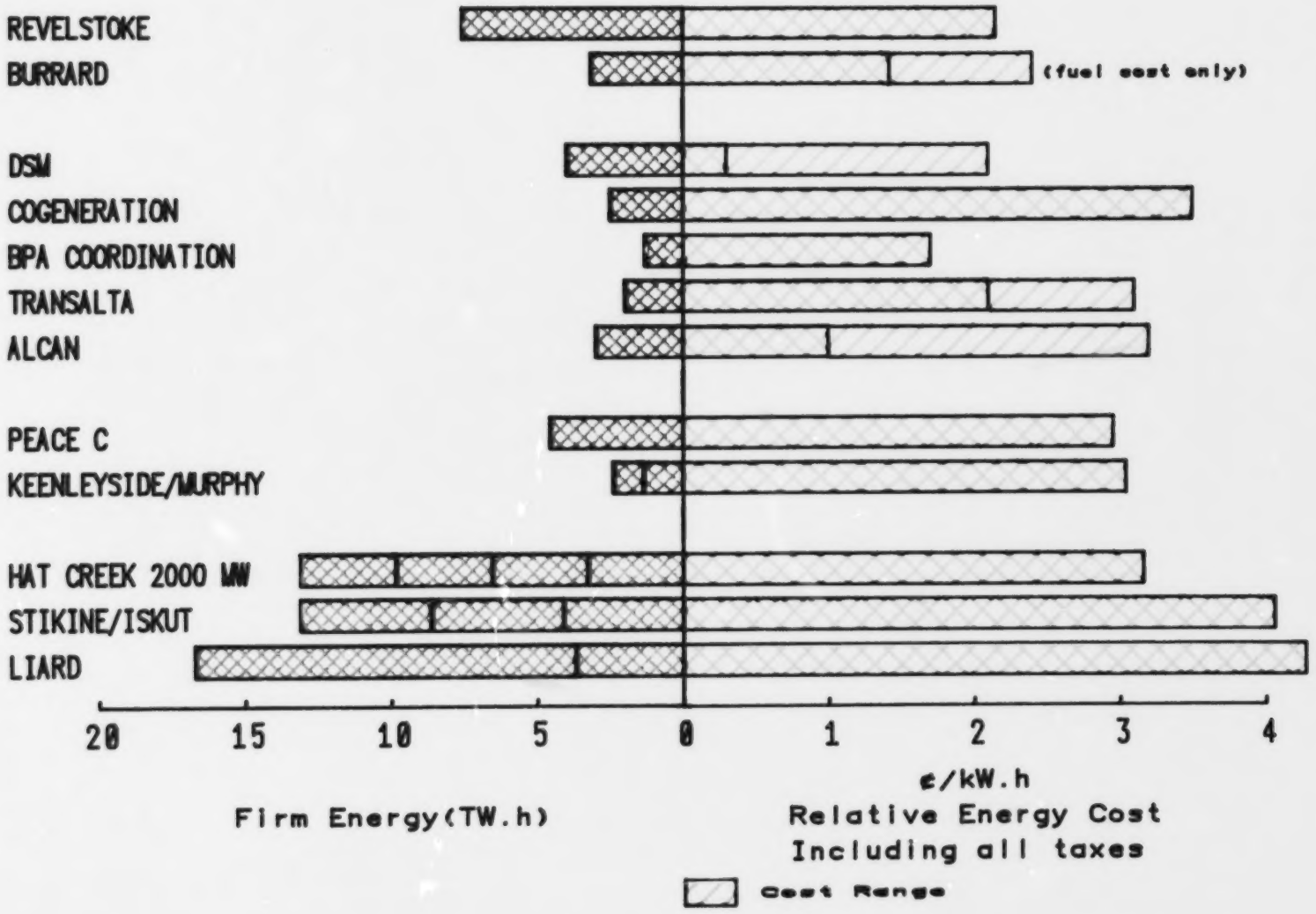


Exhibit 5-1

6. TWENTY-YEAR RESOURCE PLAN

The foregoing sections on B.C. Hydro's existing resource base, demand forecasts, marketing programs and potential resources demonstrate that uncertainty is a fundamental characteristic of both supply and demand. The selection of a Resource Plan requires determining that combination of resources which minimizes total long-term costs while meeting prescribed service standards; but it also requires proper balancing of risks arising from investing in new resources unnecessarily, or too early, against those from building too late, thus causing an unreliable supply of electricity and constraining economic development. In addition, the selected plan must be flexible enough that it can be modified to respond to potentially different outcomes.

If B.C. Hydro relied exclusively on existing resources, forecast demands suggest that these resources would be fully utilized within the next five years, and as early as three years from now if the provincial economy performed better than expected. Additional purchases using existing interconnections with other energy producers and increased emphasis on the customers' efficient use of energy may provide some additional time. But barring a deep economic downturn, the need for new sources of energy appears unavoidable by the mid 1990's.

B.C. Hydro customers enjoy a reliable supply of electricity at a price that ranks among the lowest in North America. This section describes the Plan recommended to maintain and possibly improve on this record, some of the options available, and the implications of some of the uncertainties considered.

6.1 RECOMMENDED PLAN

B.C. Hydro's recommended Resource Plan relies on a combination of coordination and purchase agreements with other energy producers; demand-side management programs; the return to the province of the Canadian entitlement to the Columbia River Treaty downstream benefits; and new generating capacity. The emphasis on coordination, purchases and DSM has resulted in the deferral of new generation by four years, from 1997/98 to 2001/02, from last year's Resource Plan, despite higher forecast demands by the turn of century in the order of 1000-2000 GW.h/annum.

The recommended Resource Plan is summarized below, and also shown graphically in Exhibit 6-1. Exhibit 6-2 indicates how the approximate contributions of all resources would stack up against the range of potential forecast outcomes.

Recommended Twenty-Year Resource Plan

Year	Resource	Annual Energy Contribution
1988	Demand-Side Management Programs	Increasing to about 3000 GW.h by 2003.
1989	Coordination of Columbia River projects with BPA	1300 GW.h
1995	Coordination/purchase agreement with Alcan	3000 GW.h
1998	Return of Columbia River Downstream Benefits	Increasing to about 4800 GW.h by 2003.
2001	Peace Site C	4700 GW.h
2004	Keenleyside	1160 GW.h
2004	Murphy Creek	1450 GW.h
2006	Hat Creek	11800 GW.h

In addition to the above resources, an allowance has been made for the purchase of energy from TransAlta, although an agreement has not yet been reached.

The selection of the next capacity addition to the system around the year 2000 focused on three projects (Peace Site C, Keenleyside and Murphy Creek), since they offer similar advantages over the alternatives: lowest energy costs among all the potential projects, sizes compatible with forecast demand growth, shortest lead times required to bring them to operation, and comparatively small environmental impacts.

No significant economic advantage was found from scheduling either the Site C or Keenleyside/Murphy developments first. Site C was chosen because its design and licensing are more advanced, thus offering the shortest lead time and maximum flexibility for potential scheduling adjustments. Beyond these developments, studies indicated that the Hat Creek thermal project offered advantages in scheduling flexibility and marginally better economics than the alternative hydroelectric projects, although further studies are still required.

The recommended plan represents the optimum scheduling of new resources and most efficient use of existing and future resources so that the expected cost of meeting a potential range of forecast demands is minimized while previously defined quality of service standards are also satisfied.

This Plan requires expenditures on fixed assets (including transmission, stations and other equipment) in the order of $100 million annually until 1993, gradually increasing to about $500 million per year by 1998, and then doubling over the next decade (1987 dollars). Total project expenditures over the ten-year period (including overheads and interest during construction but excluding inflation) would be under $2 billion.

6.2 SENSITIVITY ANALYSIS

This section reviews briefly how the recommended plan would be modified to respond to higher or lower demand growth scenarios than originally forecast, and also investigates the sensitivity of the plan to changes in the discount rate used in the economic evaluation of alternatives.

Forecast Uncertainty

Exhibit 6-3 shows in graphical form how the various resources would be made available if it was known with certainty that the Probable High or Probable Low Forecast is the actual outcome. (The dotted lines show the energy contributions under the original Resource Plan). In essence, the Probable High forecast outcome would bring about a one to two-year advancement in the scheduling of new generation and no apparent need to alter the sequencing order. Occurrence of the Probable Low forecast would allow deferral of new capacity by five years on average, and would reinforce the selection of relatively smaller projects such as Murphy/Keenleyside and Peace Site C.

Neither scenario appears to present serious disruptions to the orderly development or contracting of new resources. The Probable High forecast would be met by increasing the effort on DSM programs, purchasing additional energy from TransAlta and private power producers, and negotiating a firm gas contract for Burrard, in addition to accelerating construction of new generating plants where possible. Conversely, occurrence of the Probable Low forecast would be mitigated by a slowing down of DSM programs, reduced purchases and deferment of new capacity. It is, however, likely that commitments to the first plant in the sequence would be sufficiently advanced that a six-year deferral would be impractical. In that case, the existence of available export markets would be very important to B.C. Hydro's continuing financial strength since an energy

surplus in the order of 3000 - 4000 GW.h could temporarily exist. (Note that Exhibit 6-3 does not show any changes in timing for purchase/coordination agreements, or DSM programs.)

A drastic departure from the currently forecast "band" is given a smaller, albeit still significant, likelihood of occurrence (roughly a 25% probability of being either above the High or below the Low forecasts). Either scenario would likely bring about some disruption, since acceleration or deceleration of DSM, purchases or new generation would not be sufficient to immediately bridge the gap between demand and supply. Thus, either additional costs from resorting to more expensive resources or (perhaps unmarketable) energy surpluses would be experienced for a while.

Exhibit 6-4 summarizes the impact of the full range of alternative forecast outcomes on the timing of new generation.

Sensitivity to the Discount Rate

A higher discount rate than that used by B.C. Hydro for economic evaluations (ie. 5% net of inflation) makes capital intensive projects less competitive. For example, the use of an 8% (net) discount rate would:

- make the Hat Creek thermal development competitive with the most economic hydro projects (Site C, Murphy/Keenleyside).

- increase the economic attractiveness of energy purchases, DSM programs or coordination agreements by as much as 40% to 50%.

- make gas turbines competitive for some specific roles

In general terms, emphasis in the Resource Plan would be further increased on purchases, coordination and DSM, while hydro developments would become less attractive.

6.3 CONTINGENCY OPTIONS

A number of possible contingencies and their impact on the timing of new resources and overall system costs were examined. Some of the scenarios investigate the consequences of negative outcomes (eg. poor DSM results, no purchase agreement with Alcan, unavailability of downstream benefits to meet domestic demands); others involve the successful acquisition of additional energy from options currently under study (firm purchases from TransAlta and private power producers, full coordination with BPA).

The unavailability of the Columbia River downstream benefits would have by far the largest financial impact of all the scenarios investigated. Unless B.C. Hydro received compensation from a sale, its customers would have to contribute an additional $1 billion (present worth, 1987 dollars) over a 10-year period beginning in the mid to late 1990's, to pay for the alternative resources. Rates would increase about 10% on average over a 15-year period, and an additional $2-3 billion would have to be borrowed. New generation projects would have to be advanced by two years on average, beginning with Site C, which would be required by 1999. Keenleyside, Murphy Creek and Hat Creek would follow.

The impact of failing to secure a purchase agreement with Alcan, or from demand-side management programs that perform below expectations (currently projected energy savings were halved for this analysis) is also severe, but less dramatic. The cost to consumers would be about $300 and $400 million respectively (PW, 1987), and the impact on rates 2% to 3% on average. However, the unavailability of the large block of energy that was to be provided by the Alcan purchase beginning in the mid-1990's would have a more critical impact on the timing of new generation: Site C would then be required four years earlier, in 1997; subsequent projects would also have to be advanced, by one to three years. Poor DSM results would cause a gradual advancement of new plant, by one year on average.

Coordination and purchase agreements with TransAlta, private power producers and BPA would allow both the firming up of some secondary energy, plus some additional firm energy in the B.C. Hydro system, thereby allowing for deferrals of new generating plants. Firm purchases from TransAlta of up to 2000 GW.h by 1990 and up to 7000 GW.h by the year 2000 could generate benefits up to $500 million (PW, 1987) and lower rates by up to 4%, while borrowings could be reduced by over $1 billion. Purchases from private producers and fully coordinated reservoir operation with BPA would also generate some benefits, although they would be much smaller and less clearly defined at this point. None of these options allow for deferral of new generation by more than one year.

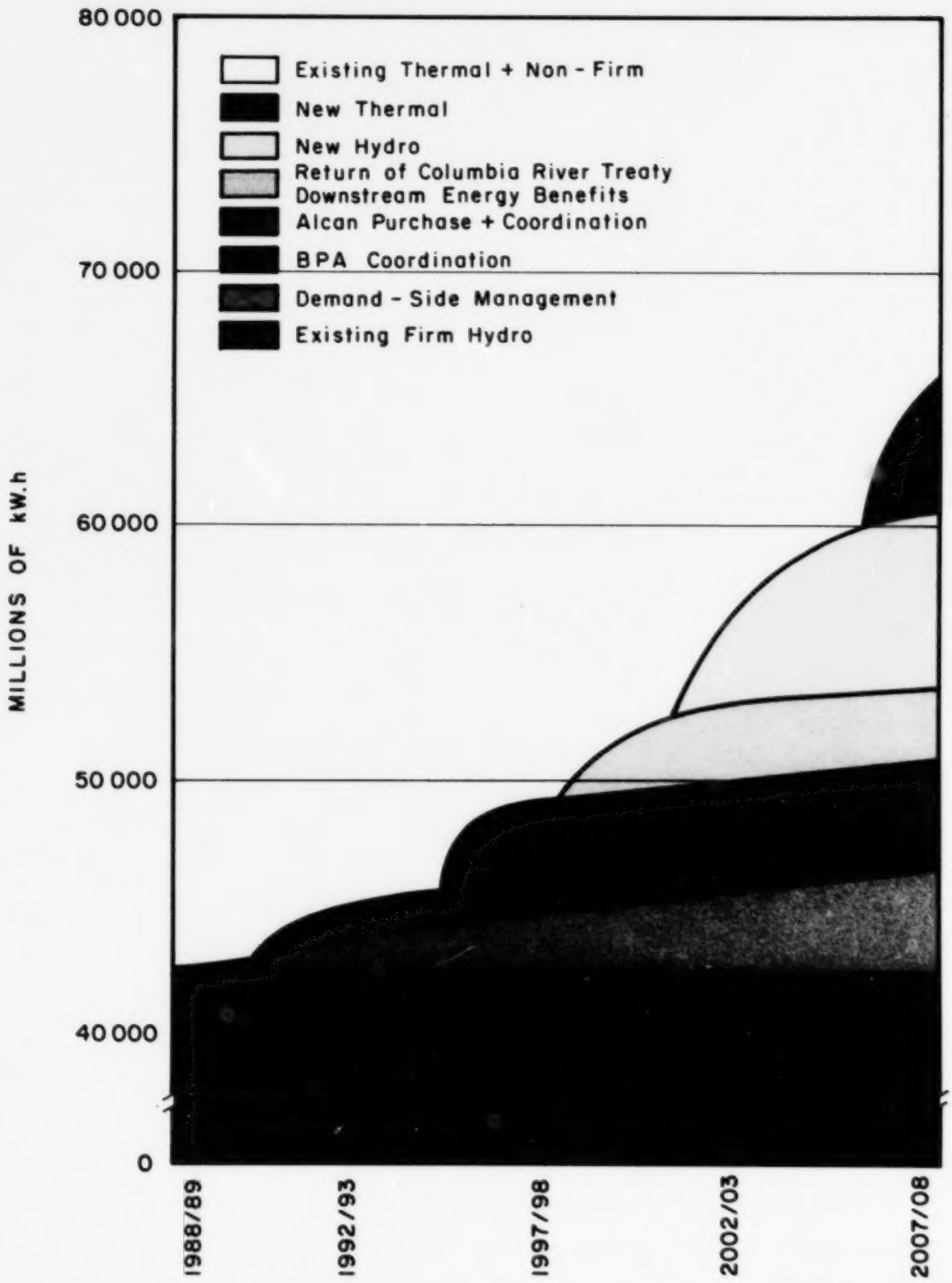
6.4 IMPLICATIONS OF POSSIBLE EXPORT SALES

Should ongoing discussions with Washington Water Power and Puget Sound Power & Light described in Section 4.4 prove to be successful, B.C. Hydro would have to commit a block of up to 1000 MW of capacity and 4000 to 5000 GW.h of energy annually to the export market. Studies to date suggest that such sales would require advancement of new generation by two to three years at an incremental cost marginally higher than that of

Peace Site C and Murphy/Keenleyside, addition of peaking units at Mica and Revelstoke, plus any transmission reinforcements that may be needed. If the contract sales ended after 20 years, as currently suggested, there would be no further impacts on the recommended Resource Plan beyond Hat Creek. However, should any of the contingencies discussed in Section 6.3 take place (in particular, the unavailability of the downstream benefits), then B.C. Hydro's Resource Plan would have to be significantly altered, and the incremental cost of serving export market demands would increase rapidly, as additional, more expensive projects would have to be brought in.

EXHIBIT 6-1

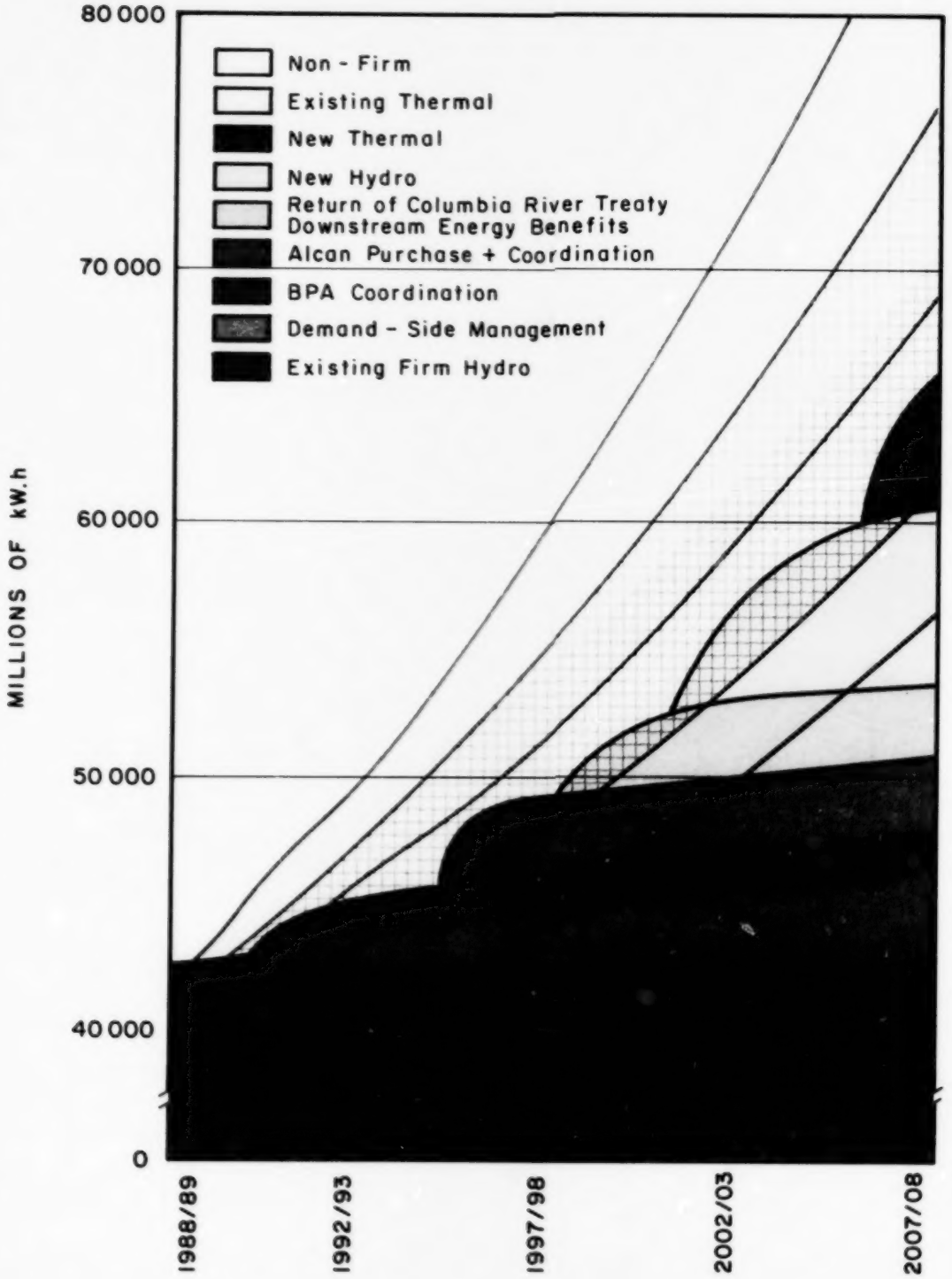
RECOMMENDED RESOURCE PLAN



MARCH 1988

EXHIBIT 6-2

RECOMMENDED RESOURCE PLAN TO MEET RANGE OF FORECAST DEMANDS



MARCH 1988

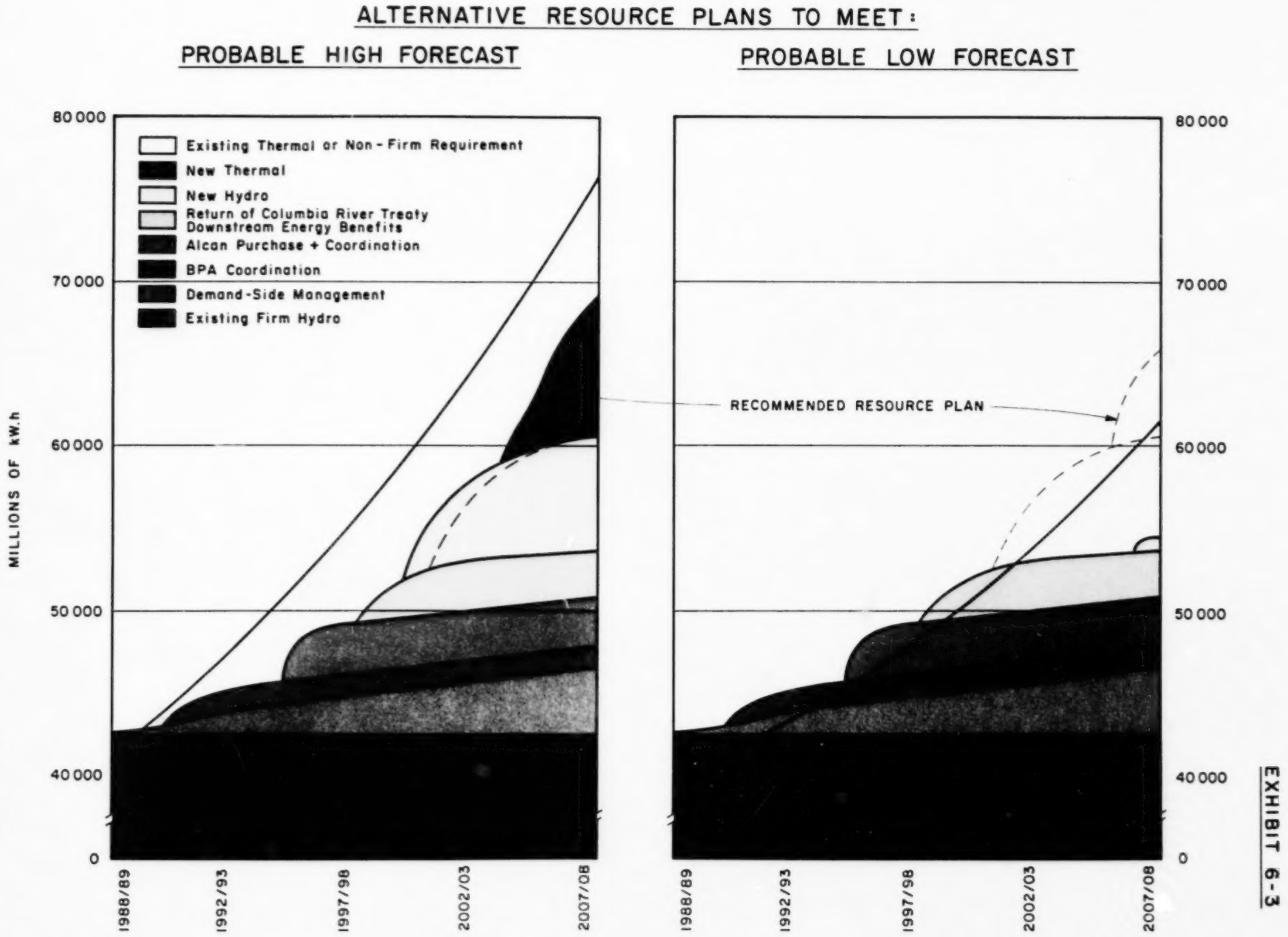

ALTERNATIVE RESOURCE PLANS TO MEET:
PROBABLE HIGH FORECAST
PROBABLE LOW FORECAST
Existing Thermal or Non-Firm Requirement
New Thermal
New Hydro
Return of Columbia River Treaty Downstream Energy Benefits
Alcan Purchase + Coordination
BPA Coordination
Demand-Side Management
Existing Firm Hydro
RECOMMENDED RESOURCE PLAN
MILLIONS OF kW.h
80 000
70 000
60 000
50 000
40 000
0
1988/89
1992/93
1997/98
2002/03
2007/08
MARCH 1988
EXHIBIT 6-3

EXHIBIT 6-4

IMPACT OF ALTERNATIVE DEMAND FORECAST OUTCOMES ON PROJECT TIMING

	Forecast Outcome				
Project	Low	Probable Low	Recommended Plan to meet range of outcomes	Probable High	High
Site C	2008	2007	2001	2000	2000
Keenleyside	2010	2009	2004	2002	1997
Murphy	2010	2009	2004	2004	2003
Hat Creek	2012	2010	2006	2004	2003
Stikine/Iskut	2018	2016	2010	2009	2007

Note: Project schedules for the High and Low forecasts, account for some adjustments to DSM and coordination. No similar adjustments have been made to either the Probable High or Probable Low forecasts.

7. ACTION PLAN

The following actions will be undertaken during fiscal year 1988/89 to ensure implementation of the recommended plan.

Demand-Side Management

B.C. Hydro will move aggressively in this area. Twenty-one demand-side management programs have been identified, some of which are currently underway. A $7.5 million 1988/89 budget has been approved for this purpose.

Purchases and Coordination

In 1988 B.C. Hydro will establish a policy for energy purchases from cogenerators and other private power producers.

Discussions are underway with Alcan to purchase surplus energy from Kemano Completion should this project proceed ahead of Alcan's need. Negotiations are expected to be finalized in 1988. Studies of coordinated operation of the Alcan and B.C. Hydro reservoirs are also proceeding.

B.C. Hydro and the Bonneville Power Administration have signed a study agreement for Coordination of the Columbia River System. It is expected that a formal agreement will be reached in April 1989 based on studies carried out during the year. Successful completion of this coordination arrangement could lead to studies of further coordinated operation between B.C. Hydro and Bonneville Power Administration.

Studies will be initiated during the year to firm up preliminary estimates of benefits from coordinated planning and operation of the TransAlta and B.C. Hydro systems.

Major Projects

The Resource Plan's increased reliance on demand-side management, purchases and coordination provides sufficient resources to defer the in-service date of the next major project until after the year 2000.

B.C. Hydro has three projects that are in an advanced stage of development and basically ready for licensing: Peace Site C, Keenleyside, and Murphy Creek. No studies are required this year to meet the in-service dates contemplated for them in the Resource Plan. However, action may be required should agreement with Alcan fail to be reached.

Additional generation would be required in 2006. While the Plan shows the Hat Creek thermal project, further studies are required to decide between it and one of the northern river hydroelectric developments. Streamflow and climate data gathering facilities are being re-established in the Stikine - Iskut, Liard and Homathko river basins. A new cost estimate is being prepared for Hat Creek.

Studies will also continue to evaluate the additional potential of existing hydroelectric sites, in order to optimize the utilization of the present system before committing to new major projects. These studies cover a number of small projects similar to the Seven Mile Raising project due to enter service in 1988. Other significant opportunities include machining of B.C. Hydro's Duncan Dam and expansion of Brilliant and Waneta Generating Stations owned by Cominco.

Rehabilitation Programs

Work will continue on a four-year rehabilitation program at the John Hart Generating Station to extend the plant life for the next twenty years.

Dam Safety rehabilitation/remedial works at Jordan River Diversion Dam, Comox Dam - Puntledge Plant, and Wilsey Dam - Shuswap Falls Dam is planned for the year.

Transmission

An upgrade of the 500 kV Peace transmission lines will be initiated to increase their thermal capacity and ensure safe conductor ground clearances are maintained.

Work will be initiated on a new Kelly Lake - Cheekeye 500 kV transmission line to provide security of supply to the Lower Mainland Area as loads develop. It is currently scheduled for completion in 1994.

If an agreement is reached with Alcan for purchase of energy from their Kemano Completion project work would commence on a new Skeena - Kitimat 287 kV transmisison line and a third Williston - Kelly Lake 500 kV transmission line.

Export Market

Development of a provincial export policy is expected in 1988. This policy could have a significant impact on future Resource Plans. In particular, given the sensitivity of the Plan to the availability of the Columbia River downstream benefits, a decision needs to be made on potential uses of this resource.

In addition, studies on two interties with U.S. utilities are underway that could impact the Resource Plan:

a) a 230 kV intertie from the Aldergrove area to connect with Puget Sound Power and Light at the Canada/US border for service in 1992.

b) a 230 kV intertie from Selkirk Substation to the Canada/US border to connect with Washington Water Power for service in 1995.

Construction of both these interties in B.C. is subject to establishing sales agreements.

APPENDICES

APPENDIX I

EXISTING SYSTEM TECHNICAL CHARACTERISTICS

The capability of B. C. Hydro's existing integrated system is summarized in Exhibit I-1.

The system is predominantly hydroelectric with 29 hydro plants; one conventional thermal plant (Burrard) and two gas turbine plants. The total nameplate capacity is 10 390 MW.

Estimates of the energy capability of the existing system (and other potential projects) are based on reservoir simulation studies using historic streamflow data which extends from October 1940 through September 1985. This 45-year period of record of average monthly flows is assumed to be representative of the range of inflows and pattern of multi-year droughts that may occur in the future.

The simulation of the existing system can be separated into the following distinct components:

1. The output of small hydroelectric projects such as Aberfeldie, Elko, Falls River, Shuswap, Spillamacheen and Walter Hardman is estimated from historic generation records.

2. Other hydroelectric projects which are operated to maximize at-site and downstream generation. This includes such projects as the Bridge, Campbell and Stave River systems as well as Buntzen, Cheakamus, Wahleach, Whatshan and others. Combined, these systems account for about 17 percent of the existing firm hydro capability.

3. The Columbia River hydroelectric system. Projects in this system are assumed to be operated in accordance with the 1988 Assured Operating Plan (AOP) for Columbia Treaty storage. For these studies of the existing system, four AOP's (1988 through 1991) were available to use as the basis for Columbia River operations. The operation of the Columbia River system varies somewhat for each AOP. The 1988 AOP was chosen as being most representative of expected future operation amongst the available plans.

   In addition to simulating the normal treaty operation of these projects, the model also simulates the operation of non-treaty storage. About 1 MAF of non-treaty storage is emptied each year during the drawdown period from September to January and is subsequently refilled in the period from June to August. This non-treaty operation is adjusted in response to system needs for various streamflow conditions. These operations are permitted under an agreement with BPA relating to the use of Columbia River Non-Treaty Storage. To model the head losses caused by BPA's use of their

1 MAF of storage under this agreement it is assumed that the BPA account is maintained half full.

4. The Peace River system. The generation on this system is adjusted to meet system requirements after the generation at other projects has been determined.

5. Thermal and energy purchases. The generation at the Burrard Thermal Plant and amount of energy purchased is adjusted to maintain Williston Lake elevations at or above desired levels.

The critical period is determined by simulating the existing system for the entire period of record and iteratively increasing the monthly loads proportionately. The largest annual load that can be served without deficits defines the firm energy load carrying capability (FELCC) of the system. The critical period is defined as the consecutive period of time during which the major system reservoirs are drawn down from full to empty while the system is serving its FELCC. For B. C. Hydro's existing system, the critical period normally extends from September 1942 through April 1946.

The duration of the critical period depends upon the amount of reservoir storage in the hydroelectric system, the amount of firm energy support available from Burrard Thermal, gas turbine plants and a number of other resources that may be available to the B. C. Hydro system and how these resources are committed to support the hydroelectric system.

These other resources include possible energy purchases from Alcan, Alberta and U.S. utilities, use of firm gas at Burrard and various other sources. Reliance on these other resources allows the system to serve a load greater than its FELCC.

For the B. C. Hydro system, this operation also impacts the length of the critical period. Serving its normal FELCC, the reservoir system fills in August 1942 and then gradually draws down to empty in April 1946. Because the system will generally be required to serve a load greater than its FELCC, it is assumed that this higher load would be served by the hydro system in the first few years of a critical period. This reduces the probability of requiring support from other resources. As a consequence, Williston reservoir experiences greater drawdown and would not fill in the freshet of 1942. As the critical period continues the reservoirs continue to draw down, but at a slower rate as the output of the hydroelectric system is reduced and reliance on other resources increased. Since the reservoir does not refill in 1942 the critical period is extended to cover the 5 1/2-year period from November 1940 through April 1946.

The capability of the existing system for the historic period of record is illustrated in Exhibit I-2.

The 912 MW Burrard Thermal plant near Vancouver has a capability of about 3400 GW·h/a when running on "Valley" gas. "Valley" gas is surplus natural gas, seasonally available between March and October, when daily requirements of B. C. Hydro's Gas Operations are less than contract levels. Burrard's firm energy capability on valley gas is 3170 GW·h/a. The firm energy capability could be increased by 2000 GW·h/a if a firm gas contract were arranged to provide fuel during those months when insufficient valley gas is available to run the plant at its maximum capability. The cost of operating the plant with this type of contract would be about one and a half times the cost of operating the plant on valley gas and the flexibility to reduce its output may be limited.

B. C. Hydro's two gas turbine plants are located at Prince Rupert and near Port Hardy on northern Vancouver island. They are primarily intended to provide short-term energy during transmission interruptions in these areas. It would be possible to produce as much as 550 GW·h/a from these plants to supplement the hydroelectric system under critical water conditions.

EXHIBIT I-1

PROJECT ENERGY AND CAPACITY DATA
EXISTING PROJECTS

Project	Capacity (MW)		Capability (GW·h)	
	Nameplate	Dependable	Average Oct.'40-Sep.'85	Critical Nov.'40-Apr.'46
Existing System				
G. M. Shrum	2 416	2 680	13 110	12 250
Peace Canyon	700	700	3 390	3 290
Mica*1	1 736	1 600	7 380	6 770
Revelstoke*1	1 843	1 843	8 180	7 580
Seven Mile*2	607	590	3 330	2 790
Kootenay Canal*3	529	529	3 240	2 470
Other Hydro	1 501	1 535	7 820	7 410
Sub-total	9 332	9 477	46 450	42 560
Burrard	912	0		3 170
Gas Turbines and Purchases	146*4	160*4		2 270
Total	10 390	9 637		48 000

Notes

*1 The energy capability of Mica and Revelstoke allows for transactions under the Columbia River Non-Treaty Storage Agreement.

*2 Seven Mile energy is net of compensation for encroachment on the Boundary tailwater upstream.

*3 Kootenay Canal energy is the sum of generation at Kootenay Canal plus WKPL and Cominco projects minus the Basic Supply.

*4 No allowance is made for any peaking contribution from purchases. These values reflect the peaking capability of the gas turbines only.

ENERGY CAPABILITY OF THE EXISTING SYSTEM FOR THE HISTORIC STREAMFLOW RECORD

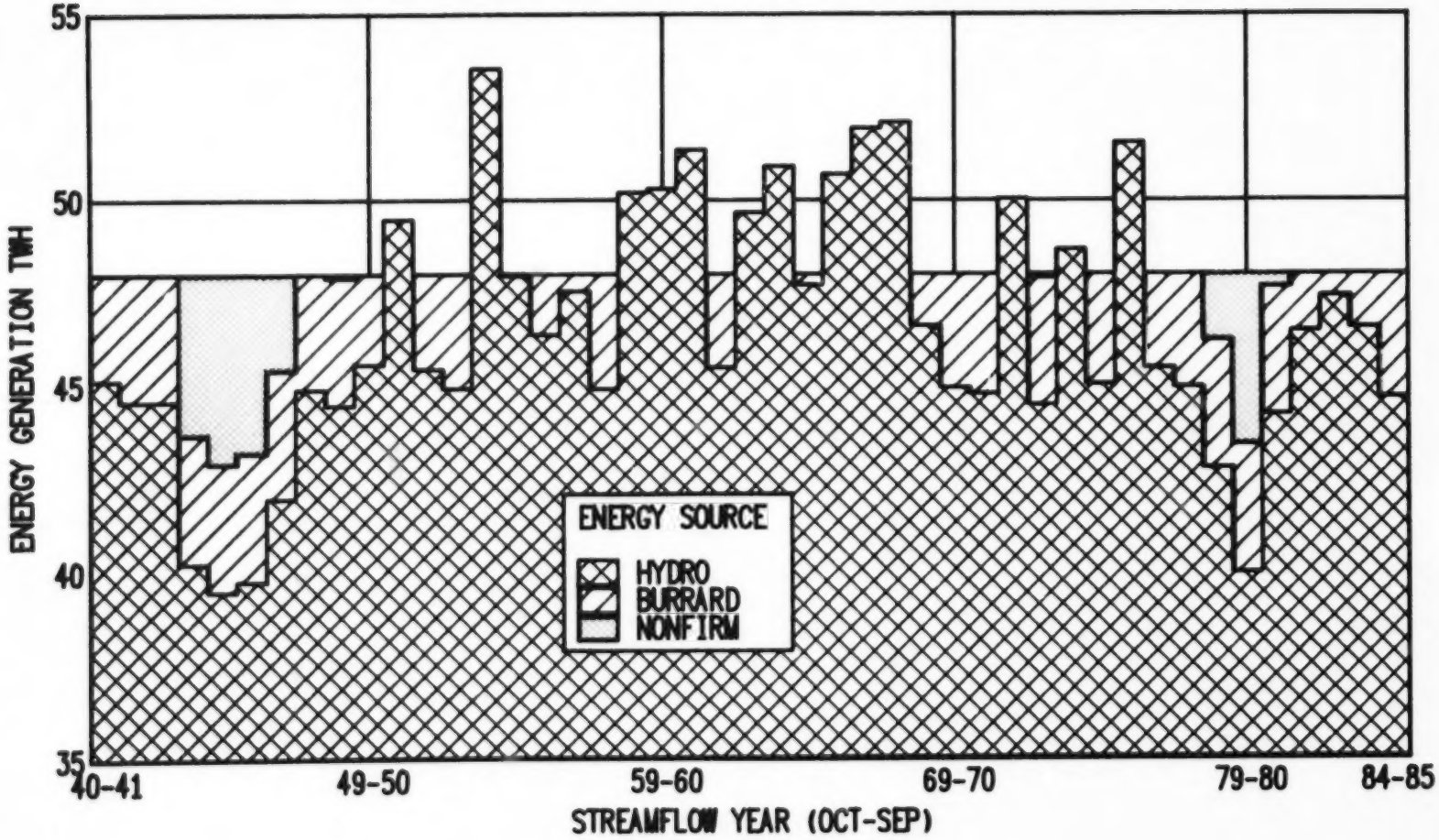


Exhibit I-2

APPENDIX II

SYSTEM TECHNICAL PLANNING CRITERIA

The technical criteria presently used for planning additions to the electric system are outlined in this Appendix. These criteria, which have evolved over the years, are modified from time to time in response to changing conditions.

LOAD FORECAST

B.C. Hydro's forecast of future electric load requirements consists of a number of projections of possible peak and energy demands. The most recent forecast (September 1987) was based on a probable economic projection, from which a band of possible electricity demand outcomes was derived. This band is referred to as the "energy planning range" about the Probable Forecast, and it contains 80% of the possible (electric load requirement) outcomes if the probable economic scenario does occur. In addition, High and Low load forecasts were prepared, on the basis of two different economic scenarios for B.C. (denominated High and Low economic projections.)

The energy planning range can be considered to arise from uncertainty in the start-up dates for major industrial loads, uncertainty in the adoption rate of conservation measures by Hydro's customers, changes in population growth, etc. Conceptually, similar bands of uncertainty would exist around the Low and High economic projections.

These assumptions were combined into a single distribution of outcomes for each future year combining the uncertainty in economic outcomes (assumed to be approximately 25%, 50% and 25% for the High, Probable and Low, respectively), with the outcome uncertainty within the Probable Forecast energy planning range. The resulting distribution was non-symmetrical, but was assumed to be normally distributed on either side of the mean.

It was found that typically, there is about a 40% probability that the load outcome will fall between the Probable Low and the Probable High (ie. within the energy planning range); a 35% probability of its being either between the High and Probable High, or Low and Probable Low; and a 25% probability of being either above the High or below the Low.

Exhibit II-1 presents the various load forecasts for the B.C. Hydro integrated system.

DEMAND-SIDE MANAGEMENT

The September 1987 load forecast already includes energy savings which are expected to arise from conservation measures voluntarily adopted by Hydro's customers in future (eg. better insulated refrigerators, more efficient appliance motors, etc.)

Additional energy savings possible through adoption of the DSM programs outlined in Section 4.3 would lower demands further. DSM energy savings are projected for optimistic, probable and pessimistic penetration scenarios. A mathematical procedure is used to determine the probability distribution of DSM energy savings which are to be deducted from the load forecast. Transmission and distribution losses are added to the original sales figures projected by marketing staff.

Exhibit II-2 summarizes the projected DSM energy savings from the twenty one residential, commercial and industrial programs currently under consideration.

GENERATION PLANNING

Methodology

A mathematical procedure is used which considers essentially all possible combinations of energy forecasts, hydroelectric system water conditions, firm and non-firm resource availabilities. The procedure calculates the "expected" usage of each resource. The schedule of new resource additions is adjusted to balance the long-term cost of generation additions against the cost of using existing resources over the short-term, on a probabilistic basis.

Using this procedure, a Resource Plan is selected to deal with the range of possible load forecasts most economically. The plan provides sufficient flexibility that higher outcomes could usually be served by resorting to additional non-firm resources but at increased cost and increased risk.

It is possible that for some adverse combinations of load, streamflow and non-firm resource availabilities, not all load could be served. The probability and extent of such deficits is calculated and serves as a measure of the risk inherent in each alternative plan considered. If major increases in load growth should occur in future, it is assumed that subsequent Resource Plans would incorporate project advancements as necessary to reduce risks to acceptable levels.

Energy

The following generation resources are considered to meet the range of forecast loads:

1. Hydroelectric resources: Their firm energy capability is estimated assuming a repetition of historic critical water conditions. Critical water conditions are defined as the lowest streamflow sequence for the hydro system as a whole during the 45-year period from 1940/41 to 1984/85. Natural inflows to major reservoirs averaged approximately 15 percent below average during the 1940-1946 critical period.

   The capability of all existing and proposed new hydroelectric plant is simulated over these 45 water years to provide an estimate of the probability distribution of hydroelectric energy. During all but the lowest streamflow periods additional secondary hydroelectric energy will be available. When available, this secondary energy would be used to serve remaining domestic load and then to reduce any higher cost energy purchases, thermal and gas turbine generation. Remaining secondary energy that might otherwise be spilled would be offered for sale in interruptible markets in British Columbia, Alberta and the United States.

2. Burrard Thermal: It is assumed that Burrard would be operated on "Valley" gas which is seasonally available between March and October, when daily natural gas requirements are less than contract levels. Current estimates of "Valley" gas availability would permit a maximum annual Burrard output of about 3400 GW.h. During a recurrence of the critical period, Burrard could contribute an average of 3170 GW.h annually, corresponding to a 40 percent annual capacity factor for the 900 MW plant.

3. Existing and future thermal generation plant whose maximum annual capacity factors could range from 60 to 80 percent, depending on the type, size and age of individual units.

   Higher cost thermal plants such as gas turbines would be expected to operate only during very low streamflow periods or to meet very high loads.

4. Firm purchase contracts.

5. Downstream benefits arising from the Columbia River Treaty. The Canadian entitlement to downstream power and energy benefits resulting from the operation of storage at the Duncan, Arrow and Mica projects was sold to the United States for a period of 30 years from the commencement of operation of each project. These 30-year periods begin to expire in 1998/99, at which time the benefits will revert to British Columbia.

Downstream benefits are assumed to vary uniformly between values estimated for Low and High growth rates in the Pacific Northwest. No correlation between Pacific Northwest and B.C. Hydro load growth is assumed.

Exhibit II-3 presents a projection of the Canadian entitlement to downstream benefits.

6. Other energy resources may include additional energy from Burrard Thermal with a firm gas contract; spot energy purchases from Alcan, TransAlta or U.S. Utilities; and purchase of co-generated energy from industrial customers. Energy from these sources is assumed to vary uniformly between their estimated minimum and maximum values. It is assumed that sufficient transmission capacity exists to deliver the energy from these resources.

Peak Capacity

The peak capacity of the electric system is designed to meet or exceed the forecast one-hour peak demand and to provide a peak reserve margin. B.C. Hydro is a member of the Western Systems Coordinating Council (WSCC), a group of electric utilities serving the western United States and Canada. The WSCC criteria allow member utilities to select one of three peak reserve criteria. B.C. Hydro, like most other utilities throughout North America, has chosen to adopt the loss-of-load probability criteria. This method comprises a probabilistic analysis of simultaneous outages of generating equipment, using a maximum risk criteria of loss-of-load of one day in ten years. That is, the probability that there would be insufficient generating resources available to meet the forecast daily peak load should be one-tenth of a day per year or less.

No allowance has been made for possible peak load reduction by curtailment of supply to large industrial customers during winter peak days. No allowance is made for emergency peak support through our interconnection with the U.S. Northwest Power Pool. However, an allowance is made for the emergency peak reserve that may be available to B.C. Hydro through existing interconnections with neighbouring Canadian utilities. The new 500 kV interconnection between B.C. Hydro and TransAlta is assumed to increase B.C. Hydro's firm peak reserve by 400 MW.

Exhibit II-4 presents an estimate of B.C. Hydro's firm capacity reserve.

Reliability

Since B.C. Hydro's integrated system is predominantly hydro, peaking capabilities have usually been sufficient to meet the loss-of-load probability criterion of one day in ten years. Thus the largest loads that can be served without incurring excessive deficits have largely

been determined by the system's firm energy load carrying capabilty (FELCC, as explained in Appendix I).

The energy reliability criterion currently in use by B.C. Hydro assumes the full range of probabilistic combinations of load uncertainty and resource availability, and limits the expected amount of unserved energy (or energy shortfall) on any given year to a maximum of 0.8% of the total annual energy demand.

However, load forecast uncertainty can be somewhat attenuated towards the future by advancing or deferring project schedules. For this reason, B.C. Hydro's energy reliability criterion assumes that the demand forecast range (band width) remains approximately constant after ten years, since this roughly corresponds to the lead time required for a new large project addition to the system.

The actual energy reliability index of 0.8% is currently under review.

Exhibit II-5 illustrates the fraction of the total load that would not be served, on a probabilistic basis, by the recommended Resource Plan.

TRANSMISSION AND TRANSFORMATION

The costs of the major additions on transmission and stations equipment required to transmit energy and capacity to the load centres are included in each alternative Plan evaluated.

Further information on additions to the system in the above-mentioned areas can be found in the document "Electric System Development Plan", which contains a description of the planned additions to the system over the next ten years, and the underlying planning criteria utilized. This report is issued annually by the System Planning Division.

B.C. HYDRO ELECTRIC GROSS LOAD REQUIREMENTS FORECAST
TOTAL INTEGRATED SYSTEM (Including SCL and WKP&L)
July 1987 Forecast

Fiscal Year	LOW SCENARIO Total Gross Req'ts (GW.h)	LOW SCENARIO Peak (MW)	P. LOW - 10% Total Gross Req'ts (GW.h)	P. LOW - 10% Peak (MW)	PROBABLE Total Gross Req'ts (GW.h)	PROBABLE Peak (MW)	P. HIGH - 90% Total Gross Req'ts (GW.h)	P. HIGH - 90% Peak (MW)	HIGH SCENARIO Total Gross Req'ts (GW.h)	HIGH SCENARIO Peak (MW)
	<---------- Range of Probable Forecasts ---------->									
1985/86 Actual	37,261	6,816	37,261	6,816	37,261	6,816	37,261	6,816	37,261	6,816
1986/87 Actual	38,139	6,467	38,139	6,467	38,139	6,467	38,139	6,467	38,139	6,467
1987/88	39,120	6,950	39,660	7,040	39,960	7,090	40,260	7,140	40,650	7,200
1988/89	39,350	6,980	40,740	7,200	41,330	7,300	41,920	7,400	42,660	7,530
1989/90	38,920	6,850	41,410	7,260	42,300	7,410	43,190	7,560	44,390	7,770
1990/91	39,210	6,910	42,100	7,390	43,290	7,590	44,480	7,790	46,310	8,100
1991/92	39,650	7,000	42,810	7,530	44,350	7,790	45,790	8,030	47,900	8,390
1992/93	39,790	7,060	43,350	7,650	45,520	8,010	47,040	8,270	49,260	8,650
1993/94	40,230	7,140	44,190	7,800	46,570	8,200	48,520	8,530	50,910	8,940
1994/95	41,140	7,300	45,030	7,950	47,740	8,410	50,010	8,800	52,750	9,270
1995/96	42,120	7,480	45,870	8,110	48,920	8,630	51,490	9,070	54,990	9,670
1996/97	43,140	7,660	46,710	8,270	50,070	8,850	52,980	9,340	57,240	10,060
1997/98	44,140	7,850	47,850	8,490	51,280	9,080	54,710	9,660	59,470	10,460
Avg. Annual Growth: %										
11 years:										
86/87-97/98	1.3%	1.8%	2.1%	2.5%	2.7%	3.1%	3.3%	3.7%	4.1%	4.5%
1998/99	45,090	8,020	48,890	8,670	52,640	9,320	56,420	9,960	61,620	10,840
1999/2000	46,140	8,210	50,030	8,880	54,120	9,580	58,250	10,280	63,970	11,260
2000/01	47,240	8,400	51,200	9,080	55,640	9,840	60,140	10,610	66,400	11,680
2001/02	48,430	8,610	52,490	9,310	57,290	10,130	62,170	10,970	68,980	12,140
2002/03	49,630	8,820	53,800	9,540	58,960	10,420	64,220	11,330	71,560	12,590
2003/04	50,810	9,030	55,140	9,770	60,680	10,720	66,330	11,690	74,200	13,050
2004/05	52,020	9,250	56,500	10,010	62,410	11,020	68,460	12,070	76,870	13,530
2005/06	53,290	9,460	57,920	10,250	64,220	11,330	70,680	12,450	79,640	14,000
2006/07	54,530	9,680	59,350	10,500	66,050	11,650	72,920	12,850	82,460	14,510
2007/08	55,790	9,910	60,830	10,770	67,930	11,990	75,230	13,260	85,410	15,040
Avg. Annual Growth: %										
10 years:										
97/98-07/08	2.4%	2.4%	2.4%	2.4%	2.9%	2.8%	3.2%	3.2%	3.7%	3.7%
21 years:										
86/87-07/08	1.8%	2.1%	2.2%	2.5%	2.8%	3.0%	3.3%	3.5%	3.9%	4.1%

EXHIBIT II-2

PROJECTED DSM PROGRAM ENERGY SAVINGS

(Equivalent generation)*

	GW.h
1988/89	93
1989/90	287
1990/91	562
1991/92	901
1992/93	1239
1993/94	1586
1994/95	1922
1995/96	1938
1996/97	2073
1997/98	2200
1998/99	2355
1999/00	2462
2000/01	2617
2001/02	2783
2002/03	2943
2003/04	3117
2004/05	3305
2005/06	3498
2006/07	3705
2007/08	3890

*Include equivalent transmission and distribution losses.

CANADIAN ENTITLEMENT TO COLUMBIA RIVER TREATY DOWNSTREAM BENEFITS*

(Estimated Range of Annual Benefits as a function of the growth rate in the Pacific Northwest)**

Year	Energy Benefits (GW.h)			Capacity Benefits (MW)
	Low PNW Growth	Probable PNW Growth	High PNW Growth	All forecasts
1998/99	620	480	360	100
1999/00	3670	2790	2060	600
2000/01	3670	2760	1990	600
2001/02	3680	2730	1920	600
2002/03	3690	2700	1850	600
2003/04	6600	4810	3230	1100
2004/05	6620	4760	3130	1100
2005/06	6640	4710	3030	1100
2006/07	6630	4660	2930	1100

*According to the Canada - B.C. agreement dated 8 July 1963, these downstream benefits "belong to B.C. absolutely for its own use".
**Based on BPA's 1986 forecast. 1987 forecast remained essentially unchanged.

ESTIMATE OF B.C. HYDRO'S FIRM CAPACITY SURPLUS

Year	Probable Load (MW)	DSM Program Reductions (MW)	Net Peak Load (MW)	Additions (MW)	Total Dependable Capacity (MW)	Required Reserve (MW)	TransAlta Support (MW)	Net Required Reserve (MW)	Actual Reserve (MW)	Reserve Margin (MW)
1988/89	7,300	18	7,282	43(SVM)	9,637	1,125	400	725	2,355	1,630
1989/90	7,410	55	7,355		9,637	1,125	400	725	2,282	1,557
1990/91	7,590	107	7,483		9,637	1,125	400	725	2,154	1,429
1991/92	7,790	171	7,619		9,637	1,125	400	725	2,018	1,293
1992/93	8,010	236	7,774		9,637	1,125	400	725	1,863	1,138
1993/94	8,200	302	7,898		9,637	1,125	400	725	1,739	1,014
1994/95	8,410	347	8,063		9,637	1,125	400	725	1,574	849
1995/96	8,630	369	8,261	520(ALC)	10,157	1,177	400	777	1,896	1,119
1996/97	8,850	394	8,456		10,157	1,177	400	777	1,701	924
1997/98	9,080	419	8,661		10,157	1,177	400	777	1,496	719
1998/99	9,320	448	8,872	100(DSB)	10,257	1,177	400	777	1,385	608
1999/00	9,580	468	9,112	500(DSB)	10,757	1,177	400	777	1,645	868
2000/01	9,840	498	9,342	450(STC)	11,207	1,222	400	822	1,865	1,043
2001/02	10,130	529	9,601	450(STC)	11,657	1,267	400	867	2,056	1,189
2002/03	10,420	560	9,860		11,657	1,267	400	867	1,797	930
2003/04	10,720	593	10,127	500(DSB)	12,157	1,267	400	867	2,030	1,163
2004/05	11,020	629	10,391	226(KL/MR)	12,383	1,290	400	890	1,992	1,102
2005/06	11,330	666	10,664	164(KL/MR)	12,547	1,306	400	906	1,883	977
2006/07	11,650	705	10,945	551(HC/MR)	13,098	1,361	400	961	2,153	1,192
2007/08	11,990	740	11,250	500(HCK)	13,598	1,411	400	1,011	2,348	1,337

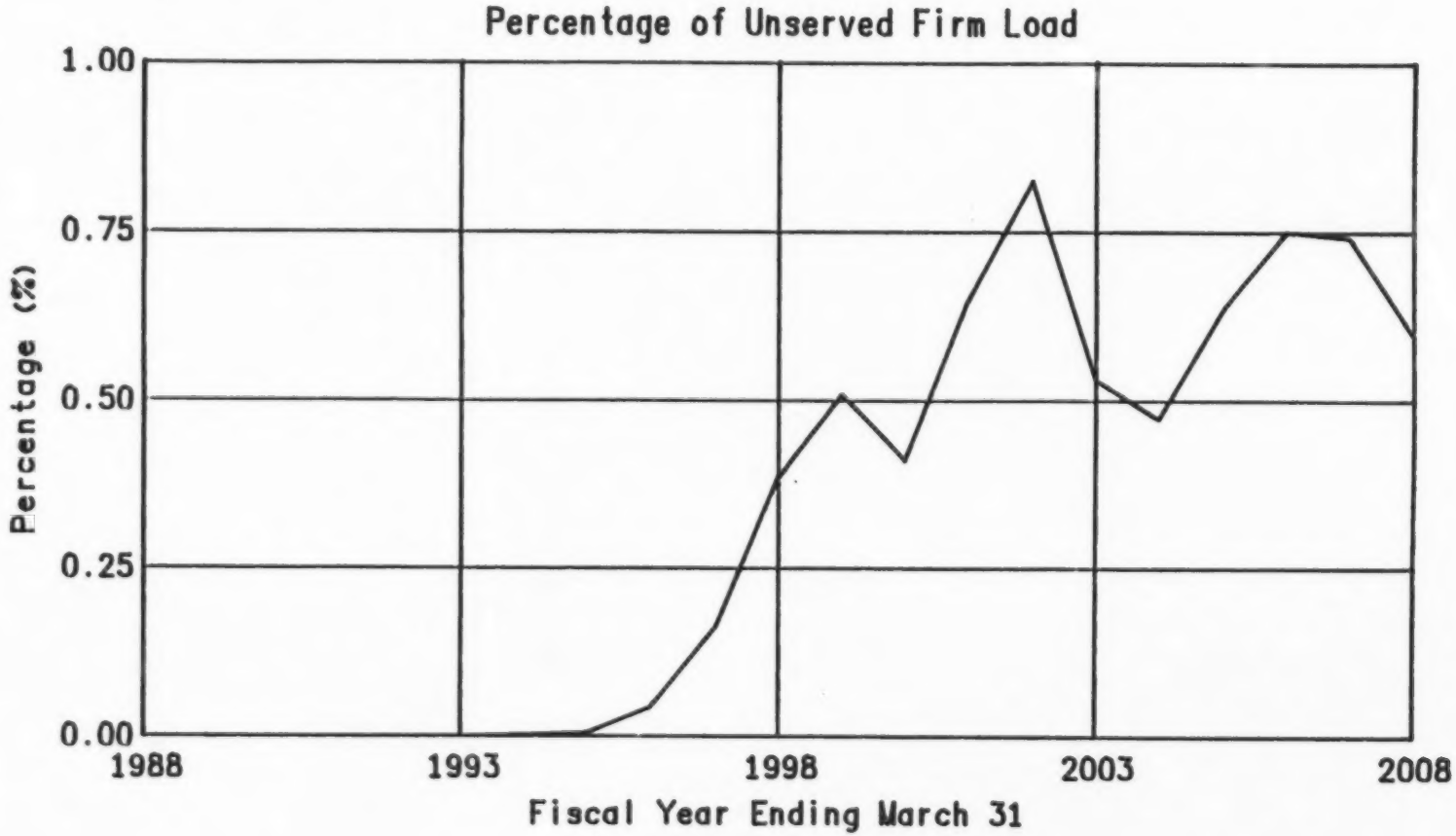
1. The required reserve is computed from loss of load probability studies. It indicates the generation reserve necessary to maintain a 1-day in 10-year risk index.

2. Reserve pooling arrangements between Alberta and B.C. (after completion of the Alberta intertie in early 1986) have resulted in a 400 MW reduction in B.C. Hydro's required reserve.

3. The Canadian Entitlement to downstream capacity benefits under the Columbia River Treaty is assumed to accrue to B.C. Hydro beginning in April 1998. The estimated capacity benefit is 100 MW in 1998/99, 600 MW from 1990/00 through 2002/03 and 1100 MW beyond 2003/04. This capacity is treated as a firm import agreement and therefore does not increase B.C. Hydro's required reserve.

4. At the beginning of 1988/89, total resources include 9434 MW of existing hydro resources and 160 MW of gas turbines. The dependable capacity of Burrard is assumed to be zero due to its uncertain fuel supply during winter peak periods.

RECOMMENDED RESOURCE PLAN



Generation Planning
23 Mar 1988

EXHIBIT II-5

APPENDIX III

POTENTIAL PROJECTS

HYDROELECTRIC

(a) Peace Site C

The project would be located on the Peace River, 7 km upstream of Fort St. John. It would comprise a 60 m high earthfill dam and a powerhouse with six 150 MW units. An 80 km long reservoir would extend upstream to Peace Canyon dam.

Peak Capacity	900 MW
Firm Energy	4570 GW·h
Average Energy	4710 GW·h

The total capital cost would be $1637 M (October 1987) including transmission. Equivalent uniform energy cost would be about 3.0¢/kW·h at a 5 percent net discount rate.

Engineering preliminary design has been completed. Hearings for an Energy Project Certificate were completed in November 1982, and the project was approved in principle. Construction timing is subject to review of future energy requirements (or export considerations). The project could be brought into service as early as 1995.

The reservoir would flood potential agricultural land now within the Agricultural Land Reserve and would require the relocation of some families in the project area. Trapping and hunting by native people would be adversely affected by access roads along the proposed transmission line route.

(b) Keenleyside

Keenleyside dam was constructed as a storage project to provide flow regulation under terms of the Columbia River Treaty. The Keenleyside powerplant project would consist of a powerhouse on the north bank of the river adjacent to the existing dam. The powerhouse would contain three 80 MW units.

If the Murphy Creek project were to be constructed soon (within a few years) after the Keenleyside powerplant project, the Keenleyside design may be modified to three 60 MW units to allow for reduction of capacity due to operation at higher tailwater levels caused by the Murphy Creek project.

Peak Capacity	240 MW	180 MW
Firm Energy	1040 GW·h	700 GW·h
Average Energy	1160 GW·h	760 GW·h

Transmission would link the generating station to the main B. C. Hydro grid at the Selkirk substation.

The total capital cost would be $347 M (October 1987) including transmission for the 240 MW plant or $318 M (October 1987) including transmission for the 180 MW plant. Equivalent uniform energy cost would be about 2.5¢/kW·h for the 240 MW plant and about 2.9¢/kW·h for the 180 MW plant at a 5 percent net discount rate.

Engineering preliminary design has been completed for the 180 MW alternative, and has been adjusted to include cost estimates for the 240 MW alternative.

Environmental and socio-economic studies have been completed to the level believed to be sufficient to support an application for an Energy Project Certificate.

The Keenleyside project is not expected to cause any significant environmental impacts and would provide a positive stimulus to employment in the area which has an experienced construction labour force.

The project could be brought into service as early as 1997.

(c) Murphy Creek

The Murphy Creek project would be located on the Columbia River 3 km upstream from Trail. This low-head development would consist of an earthfill dam with a powerhouse on the west bank containing five 55 MW units. It would be linked to the main B. C. Hydro transmission grid with a short loop to the Keenleyside-Selkirk transmission line.

Peak Capacity	275 MW
Firm Energy	1690 GW·h (following a 180 MW Keenleyside)
	1380 GW·h (following a 240 MW Keenleyside)
Average Energy	1800 GW·h (following a 180 MW Keenleyside)
	1450 GW·h (following a 240 MW Keenleyside)

The energy figures shown above are net amounts after allowances for the losses caused by higher tailwater levels at the existing Brilliant powerplant and at the proposed Keenleyside powerplant.

The total capital cost would be $677 M (October 1987) including transmission. Equivalent uniform energy cost would be about 2.9¢/kW·h at a 5 percent net discount rate if it followed a 180 MW Keenleyside

project, or about 3.6¢/kW·h at a 5 percent net discount rate if it followed a 240 MW Keenleyside project.

Engineering preliminary design studies for Murphy Creek have been completed. Environmental and socio-economic studies have been completed to a level believed to be sufficient to support an application for an Energy Project Certificate.

It would be necessary to relocate about 70 households adjacent to the proposed reservoir, and some sections of highway and railway would have to be relocated. There would also be a significant impact upon the Kokanee fishery along this portion of the Columbia River. From a socio-economic viewpoint, this project would provide a positive stimulus to employment in the area which has an experienced resident construction labour force.

The project could be bought into service as early as 1998.

(d) Seven Mile - Unit 4

Addition of unit 4 would complete development of the Seven Mile Project on the Pend-d'Oreille River in southwestern B. C. The project would consist of the addition of the fourth unit to increase the nameplate capacity of the plant to 810 MW.

Peak capacity	202.5 MW
Firm Energy	140 GW·h
Average Energy	290 GW·h

The total capital cost would be about $70 M (October 1987). Equivalent uniform energy cost would be about 1.5¢/kW·h at a 5 percent net discount rate.

Total construction time would be about 4 years. There would be no environmental effects since reservoir levels would not be altered.

(e) Stikine-Iskut

The 2900 MW Stikine - Iskut development would harness the hydroelectric potential of a major undeveloped river basin in northwestern British Columbia. The four hydroelectric sites being considered for power development are: Stikine Canyon and Tanzilla on the Stikine River; Iskut Canyon on the Iskut River, and a site on More Creek just upstream of its confluence with the Iskut River. In addition, diversion of the headwaters of Forrest Kerr Creek into the headwaters of More Creek is proposed in order to increase the potential of the More Creek site.

Peak Capacity	2 900 MW
Firm Energy	13 130 GW·h
Average Energy	15 570 GW·h

The total capital cost of the development would be $6343 M (October 1987) including transmission. Equivalent uniform energy cost would be about 4.0¢/kW·h at a 5 percent net discount rate.

Engineering preliminary design studies for all projects were partially complete when work on the development was suspended in 1983. An Interim Assessment report was prepared in 1983 on the status of all work to date.

Major environmental impacts include: possible effects of flow regulation on migrating and spawning salmon; partial flooding of the Grand Canyon of the Stikine; effects of flow regulation on the Stikine estuary within Alaska; impacts on the communities of Telegraph Creek, Iskut and Dease Lake caused by the introduction of a large work force in the area; and the effect of transmission line access roads upon previously inaccessible wildlife habitats.

The first project in the development could be brought into service as early as 2003.

(f) Liard

The Liard development would initially consist of two projects in an undeveloped river basin in northern British Columbia: the 2490 MW Devils Gorge storage and power project, 25 km downstream from the Liard River Hotsprings Provincial Park; and the 700 MW Hell Gate power project, 40 km downstream from Devils Gorge. A future development at Beavercrow, 85 km downstream from Hell Gate, could follow and would provide an additional 1128 MW of capacity and 6190 GW·h/a of firm energy.

Peak Capacity	3 190 MW
Firm Energy	16 730 GW·h
Average Energy	18 380 GW·h

The total capital cost for the two project arrangement would be $6664 M (October 1987) including transmission. Equivalent uniform energy cost would be about 4.3¢/kW·h at a 5 percent net discount rate. With Beavercrow, the three project arrangement would have total capital cost of $10487 M (October 1987) including transmission and would have an equivalent uniform energy cost of about 4.6¢/kW·h at a 5 percent net discount rate.

Engineering feasibility studies have been completed for the Devils Gorge and Beavercrow projects. A limited one-year feasibility study for the Hell Gate project and a one-year preliminary design study on the Devils Gorge project were completed prior to 1982 when all studies were suspended. Interim engineering and environmental reports and a summary report were prepared on the work completed to date. Preliminary transmission system and corridor selection studies were in progress when the program was terminated.

Flooding of the Liard River Hot Springs and the Muddy River Indian Reserve as well as relocation of portions of the Alaska Highway and five settlements along the highway are major environmental concerns. Native people's traditional hunting areas would be adversely impacted by access roads into currently inaccessible areas. Effects of flow regulation could extend downstream as far as the Mackenzie Delta.

The development could be brought into service as early as 2008.

(g) Homathko

The Homathko development would initially consist of a two-powerplant (710 MW) scheme in an undeveloped river basin in the Coastal Mountains, with a 290 MW power project on Mosley Creek and a 420 MW power project at Waddington Canyon on the Homathko River. Transmission from the project would feed into central British Columbia and to Vancouver Island. A storage dam on Tatlayoko Lake with a dam and a 185 MW powerplant on the Homathko River at Nude Canyon could be constructed later.

	2 Projects	3 Projects
Peak Capacity	710 MW	895 MW
Firm Energy	3500 GW·h	4440 GW·h
Average Energy	3430 GW·h	4360 GW·h

The total capital cost for the two project scheme would be $1789 M (October 1987) including transmission. Equivalent uniform energy cost would be about 4.6¢/kW·h at a 5 percent net discount rate. The three project scheme would have a total capital cost of $2349 M (October 1987) including transmission. Equivalent uniform energy cost would be about 4.7¢/kW·h at a 5 percent net discount rate.

Engineering, properties and environmental overview studies and one year of preparation for feasibility studies have been completed. Two years of a limited feasibility study have also been completed.

The development would produce seasonal changes in the Homathko River streamflow, which could affect salmonids spawning in the lower reaches of the river. Fishing impacts are expected to be manageable. There appear to be no major environmental impacts associated with the transmission lines although some social concerns, particularly between Campbell River and the mainland and on Vancouver Island, might be expected.

The development could be brought into service as early as 2002.

THERMAL

(a) Hat Creek

This project would be located in the Hat Creek valley, about 80 km west of Kamloops. It would have two basic components, a mine and a powerplant, both located at the north end of the valley. Coal would be mined in a large open pit mine and transported by conveyor to the powerplant located 4 km to the northeast and 500 m above the mine. Three different project arrangements have been studied: a 2000 MW (net) plant; a 720 MW (net) plant; and a 204 MW (net) plant. For the 2000 and 720 MW plants, steam would be condensed by evaporative cooling towers, using water from the Thompson River for make-up. The 204 MW plant would use Hat Creek water for cooling. Flue-gas treatment would remove about 90 percent of the sulphur dioxide.

Peak Capacity	2000 MW	720 MW	204 MW
Firm Energy	13140 GW·h	5050 GW·h	1340 GW·h
Average Energy	11800 GW·h	4230 GW·h	1200 GW·h

The total capital cost of the 2000 MW alternative would be $2915 M (October 1987) including transmission. Equivalent uniform energy cost would be about 3.2¢/kW·h at a 5 percent net discount rate. For the 720 MW alternative the total capital cost would be $1515 M (October 1987) including transmission. Equivalent uniform energy cost would be about 4.1¢/kW·h at a 5 percent net discount rate. The cost estimates for the 2000 MW and 700 MW alternatives are being revised. The above costs are based on recent estimates by Shawinigan-Integ for the powerplant and Fitzpatrick Mining Consultants for the mine. New estimates for the 204 MW alternative were not prepared.

Preliminary engineering, detailed environmental studies and an environmental impact statement have been completed for the 2000 MW project. Some property has been acquired in the Hat Creek valley and coal licences covering the whole valley are being maintained.

Emissions from the 2000 MW plant are not expected to affect public health adversely. There is potential for injury only to the most sensitive vegetation species in the vicinity of the project. Runoff and seepage from mine waste disposal and coal storage would not be discharged and surface water would only be discharged after treatment for sediment control. Increased water temperature in the Hat Creek downstream of the plant might affect some aquatic life. Area alienated would total less than 2500 ha of range and crop land. Over 3200 construction and operating employees would be needed during the peak of construction and over 1200 permanent new jobs would be created. The scale of the project would have some impact on local housing, services and facilities and on native Indian bands who live near the development.

For the 700 MW plant it can be assumed that the impacts would be similar to the 2000 MW plant, but on a reduced scale.

For the 204 MW plant, most impacts would be reduced further. There would be no Thompson River intake or pipeline; instead, water would be taken from Hat Creek and the impacts downstream would, therefore, increase, but overall there would be less impact.

The 2000 MW project could be brought into service as early as 1998.

OTHER POTENTIAL PROJECTS

Other projects which Hydro has studied in the past are listed below. The level of knowledge on these projects generally is lower than the preceding projects, or their costs are too high to include in alternative plans at this time.

Project	Capacity (MW)	Firm Energy (GW·h)	Average Energy (GW·h)
Hydroelectric			
Border	250	1510	1610
Elaho	340	1560	2100
McGregor Lower Canyon	360	1720	1950
Brilliant Expansion	150	510	680
Waneta Expansion	190	150	310
Falls River Redevelopment	22	-	90
Thermal and Alternative			
East Kootenay Thermal	600	3940	3860
Combustion Turbine-Simple Cycle	636	2500	1100
Solar-Power Tower	100	200	175
Wind Farm	16	30	30